U.S. Petroleum Product Supply—Inventory Dynamics

A Report of the
National Petroleum Council
December 1998

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Archie W. Dunham, Chair, Committee on Product Supply

NATIONAL PETROLEUM COUNCIL

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U.S. DEPARTMENT OF ENERGY

Bill Richardson, *Secretary*

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

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

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December 15, 1998

The Honorable
Bill Richardson
Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the Council's report entitled *U.S. Petroleum Product Supply—Inventory Dynamics.* This report provides the Council's advice on the specific questions contained in the September 16, 1997, letter of request from the Secretary of Energy.

The most challenging question asks, in effect, whether the market-driven efficiency gains seen in the petroleum product supply system over the past several years have inadvertently increased the public's exposure to larger and more frequent retail price swings. As detailed in the enclosed report, analysis of available data and the judgment of the members lead the Council to conclude that this is not the case. This conclusion is based primarily on the following:

- The observed declines in product inventories are essentially limited to finished gasoline in terminals and are largely the result of consolidations and accounting changes. In general, consolidations have reduced unavailable inventories and have not affected supply flexibility.

- Domestic refiners maximize the use of their downstream conversion facilities, the critical units for manufacturing gasoline. While typically operated at or above nameplate capacity, the mix of gasoline and distillate yields from these facilities is adjusted in response to market needs. Distillation capacity utilization, though increasing, is not the correct gauge of manufacturing flexibility.

- Incremental supplies from Caribbean and other Atlantic Basin refineries will remain available as an ongoing supply source to the United States and will continue to be available to respond to market imbalances. From some locations, in fact, these supplies can arrive in U.S. East Coast ports faster than supplies from U.S. Gulf Coast refineries.

- Significant price excursions of major light petroleum products in the United States will continue to be driven primarily by movements in the global price of crude oil. Non-crude oil related upward retail price movements tend to be driven by either an infrequent large event or a confluence of smaller events in the same direction.

In response to a highly competitive market, suppliers of refined petroleum products have created an increasingly sophisticated and efficient system that provides large volumes of affordable fuels to U.S. consumers. There are, however, two caveats from this report that must be kept in mind:

- The context of the analysis is "normal" market conditions, not emergency conditions such as might occur in conjunction with a large military mobilization or other significant market intervention.

- The time frame of the analysis is 1998 to 2002, which, by agreement, excludes the impact of additional environmentally driven product specification changes. No conclusions from this report should be drawn past 2002, especially regarding U.S. refinery flexibility or the availability of products from foreign refineries meeting more stringent U.S. specifications.

The National Petroleum Council sincerely hopes the enclosed report will be of value to the Department of Energy.

Respectfully submitted,

Joe B. Foster

Joe B. Foster
Chair

Enclosure

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INTRODUCTION

STUDY REQUEST

On September 16, 1997, Secretary of Energy Federico Peña requested that the National Petroleum Council (NPC) undertake a new study on the dynamics of U.S. petroleum product inventories. Specifically, he requested that the NPC address the following issues:

1a. What are the factors behind the long-term decline in product inventories and is the trend likely to continue over the next few years?

1b. Were the inventory levels of 1996 an anomaly or a steepening of this long-term decline?

2a. In the context of these long-term trends, are minimum operating levels (inventories) still a useful concept for the Department to use as a bench-mark or indicator of possible future problems in supplies or prices?

2b. Can the NPC define such levels of inventories (either as minimum operating levels or some other construct) that, if not maintained, would cause supply problems; and how do such levels compare to those identified in the 1989 study or the minimum observed inventories now used by the Energy Information Administration?

3. In the context of these apparently permanent lower inventory levels, will capacity limitations in the industry, coupled with demand growth (particularly for middle distillates) diminish the industry's ability to respond to dynamic conditions? Will larger price swings become a more frequent and necessary element of market balancing?

(See Appendix A for the complete text of the Secretary's request letter and a description of the National Petroleum Council.)

STUDY ORGANIZATION

To respond to the Secretary's request, the NPC established the Committee on Product Supply. The Committee was chaired by Archie W. Dunham, President and Chief Executive Officer, Conoco Inc. Robert W. Gee, Assistant Secretary, Policy and International Affairs, served as the Committee's Government Cochair. To assist the Committee, a Coordinating Subcommittee was formed. This Subcommittee was chaired by Jim W. Nokes, President, Refining and Marketing, North America, Conoco Inc. Barry D. McNutt, Policy Analyst, Office of Energy Demand Policy, U.S. Department of Energy, served as Government Cochair of the Subcommittee. (See Appendix B for rosters of the Committee and Coordinating Subcommittee.)

STUDY APPROACH

This study answered specific questions posed by the Department of Energy by compiling and analyzing U.S. data and reviewing notable events impacting domestic petroleum supply and demand. This study analyzed historical inventory trends and price swings through mid-1998 for major light petroleum products (gasoline, distillate, and kerosene jet fuel). An attempt was made to identify factors affecting price movements.

The study was approached from four perspectives. First, inventory trends and estimated lower limits of steady-state system inventory requirements were identified. Second, economic and operating factors influencing inventory levels and changes were analyzed. Third, relationships between inventory behavior and prices were qualitatively reviewed. And finally, a supply/demand balance based on estimated changes in demand, U.S. refining capacity, and gasoline import availability was developed to determine whether the U.S. product supply system was becoming more tightly constrained and whether the probability of price swings would increase. This analysis was based on the assumption that the U.S. refining and product distribution system would not be constrained by significant regulatory product quality changes that might limit system capacity or flexibility. The impact of these potential changes is outside of the scope of this study, but is planned to be addressed in an NPC study beginning in the spring of 1999. Given the uncertainty of changes coming in the post-2002 period, the time frame of this inventory study was limited to 1998–2002.

Conclusions about the relationship between inventory, price, and price movements are analyzed in the context of U.S. inventories of major light petroleum products in the primary system. This study did not conduct an exhaustive analysis of the many points of interface between the U.S. primary supply system and other types of inventory in the United States (e.g., unfinished inventory, and finished products in secondary and tertiary inventory), nor did it address inventories held outside the United States. Because the supply of crude oil is fundamental to the ability of the refining system to supply products, the study also investigated some aspects of U.S. crude oil inventory.

REPORT STRUCTURE

Chapter One

Chapter One provides an overview of the size, scope, and segments of the global petroleum business, and reviews the role of inventory in the major light petroleum product market in the United States. In addition, the chapter discusses the key changes impacting the product supply and distribution system since 1986.

Chapter Two

Chapter Two investigates the behavior of gasoline, distillate, and kerosene jet fuel inventories since 1986. A new construct defined as lower operating inventory (LOI) is introduced, and LOI levels for these products are identified based on observed data.

Chapter Three

Chapter Three examines the dynamics among supply, demand, and price, highlighting the relationship between inventories and price. It analyzes historical price increases that drew public attention and identifies those driven by product markets versus crude oil markets. It concludes with a more detailed description of the gasoline price increase in the summer of 1997, to illustrate how a supply/demand imbalance can be resolved through market mechanisms.

Chapter Four

Chapter Four is a discussion of events from late 1995 through mid-1998 that describes inventory behavior during recent periods of reduction and growth. These periods were particularly illustrative as inventories were driven, at times, to levels approaching both perceived minimums and maximums of their operating range.

Chapter Five

Chapter Five assesses the outlooks of future major light petroleum product demand, import availability, and U.S. refining capacity through 2002. Additionally, likely market responses to a higher demand case are discussed. These projections are used to examine the supply system's ability to respond to dynamic conditions and the potential consequences on market prices.

ROLE OF INVENTORY

This study focuses on major light petroleum products in the United States, but it is important to understand this market in the context of the larger global petroleum market. Production and delivery of petroleum products involves at least 14 separate activities, as shown in Figure 1. This figure illustrates the various components of the global petroleum supply chain and the points at which inventories occur. Many unique competitors participate in this supply chain. Some are integrated throughout the chain while others only specialize in certain segments. Competition in the global marketplace drives adoption of the most efficient strategies, including those related to inventory management.

Inventory is held at many points in the global supply chain and plays several roles. Figure 1 also identifies the focal point of this study—major light petroleum products in the primary system in the United States. The primary system comprises only one component of global inventories and contains only about half of the total U.S. inventory of major light petroleum products. Although movement and processing of a specific crude oil can take months due to the geography and complexity of the supply chain, in reality products are continuously being shipped from over 150 U.S. refineries and arriving at several hundred points of final distribution. This continuous process allows prompt reallocation of products to meet fluctuations in local or regional needs.

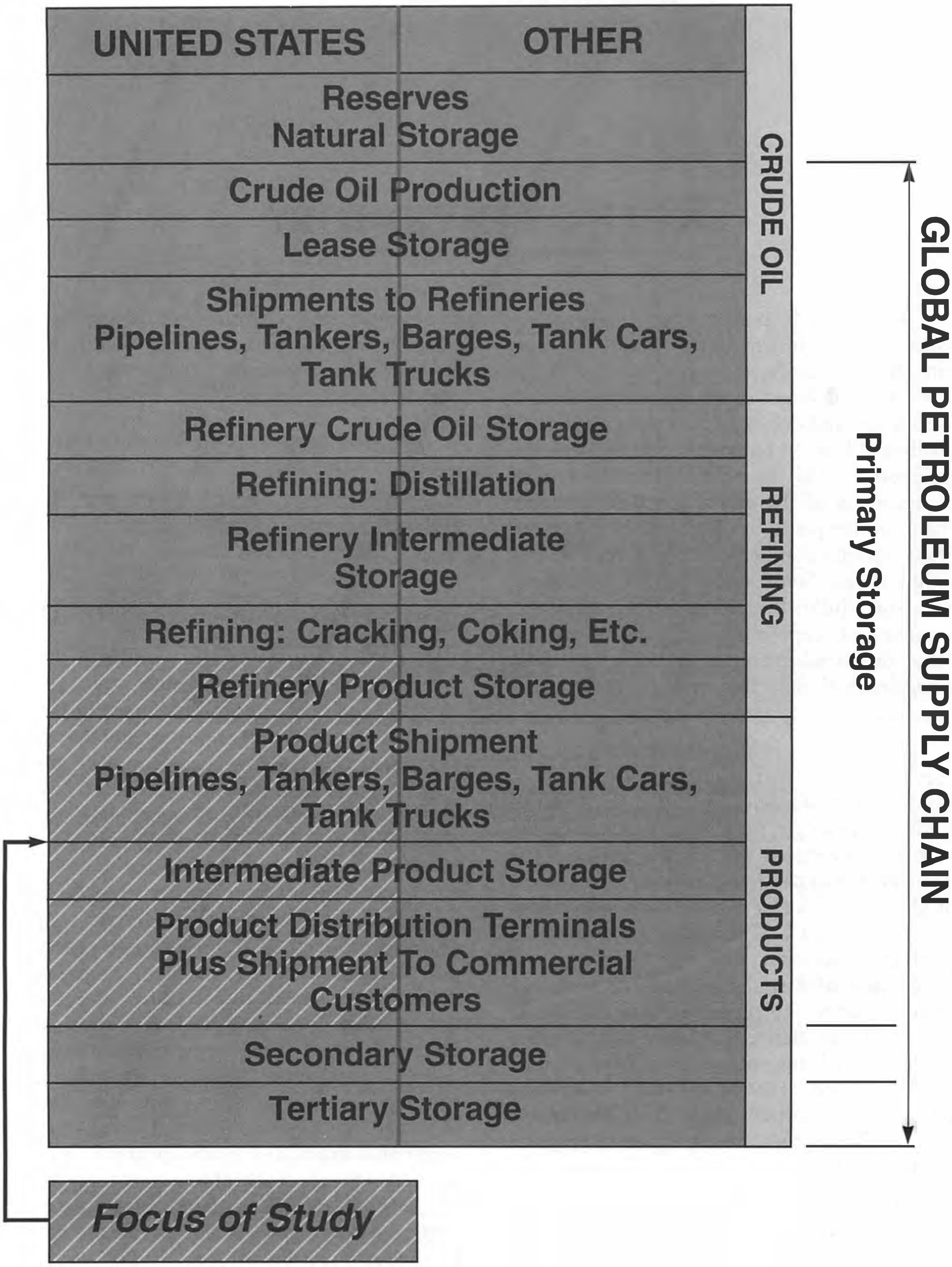
Products move from primary storage into secondary storage, which includes distributor, retail station, and industrial and commercial inventories. Product from secondary storage is transferred to the consumer or end-user, making up the third inventory category called tertiary storage.

In facilitating the operation of this supply chain, inventory plays several roles: operational necessity, component of supply, financial opportunity, and protection against a worldwide emergency.

INVENTORY AS AN OPERATIONAL NECESSITY

Under normal circumstances, the flow of crude oil and products around the world is not always constant, homogenous, or uninterruptable, due in part to the batch nature of some movements. One function of petroleum inventory is that of an operational buffer between supply and demand. This role requires sufficient inventory to allow the supply system to operate efficiently. Inventory provides the interface between each segment of the industry's supply chain of production, transportation, refining, product distribution, and marketing, and allows the supply system to balance different rates of flow in different parts of the system. Inventory used as an operational necessity includes tank bottoms, pipeline fill, in-transit inventory, and working inventory. This inventory is normally not available to meet demand because it is required to maintain a steady operation. As the industry achieves higher throughput rates without adding significant new infrastructure, improved operational efficiency is represented by a reduction in the apparent days of supply of

Figure 1. Global Petroleum Supply Chain.



inventory. While this number is reflective of improvements in efficiency, it does not reflect a lower level of supply reliability.

INVENTORY AS A COMPONENT OF SUPPLY

Another role of inventory is that of a component of supply. This inventory is produced and stored in order to meet expected future demand. Product demand has seasonally and regionally specific characteristics. Off-season storage of inventory may serve as an economic method of supplying future demand versus a more timely purchase or production increase. In the United States, heating oil is the product that has historically been the most dependent on seasonal inventory builds to supply periods of peak demand. Companies also build inventories in preparation for planned maintenance in the production, refining, and logistical systems. To ensure that customer needs are met, additional inventories are normally held as protection against variability in the elements of the supply chain as well as in customer demand. The quantity and use of these inventories do vary and are subject to individual company operating philosophies.

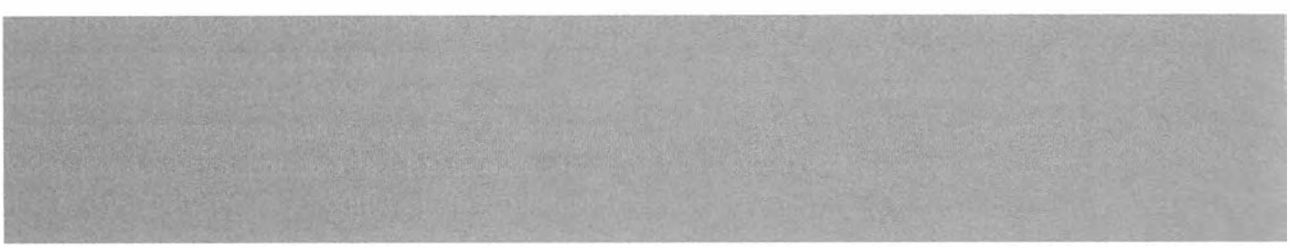
INVENTORY AS A FINANCIAL OPPORTUNITY

Physical inventories can also be used to improve economic performance. Inventory held for this purpose is referred to as "discretionary" because it is in excess of the level necessary for operational efficiency. This capability is, to varying degrees, available in all segments of the supply chain: production, refining, terminaling, commercial end-use, and consumers. In the primary sector, these inventories appear predominantly in terminals. Most companies actively manage their physical product inventory in response to economic incentives.

INVENTORY AS PROTECTION AGAINST A WORLDWIDE EMERGENCY

A significant portion of the world's petroleum inventory is tied up in compulsory inventories. Most governments of leading industrialized countries mandate minimum levels of petroleum inventories at some point in the supply chain due to national security concerns, or requirements for membership in organizations such as the International Energy Agency and the European Economic Union.

The United States' Strategic Petroleum Reserve is the largest government crude oil stockpile. It was started in 1975 as part of the Energy Policy and Conservation Act. The Strategic Petroleum Reserve reached a high of 591 million barrels in 1995 and currently contains 563 million barrels, accounting for about 35 percent of the primary U.S. petroleum inventory. The industry remains strongly supportive of holding these inventories for use during significant crude oil supply disruptions.



Executive Summary

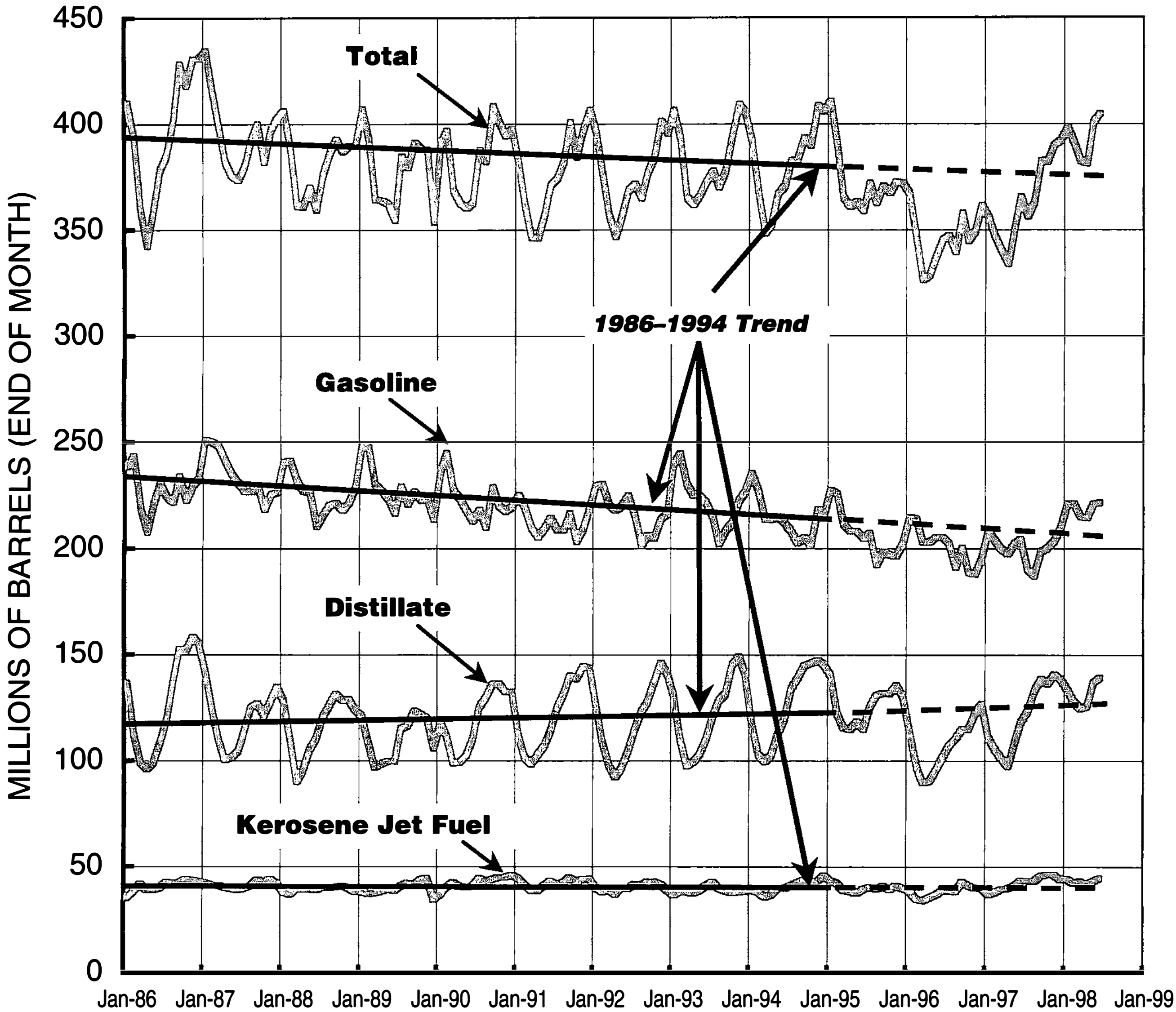
Over the study period, the total inventory of major light petroleum products is likely to continue the slow historical downward trend shown in Figure 2. The individual product inventory trends indicate that the overall major light petroleum product downward trend is the result of a downward trend in gasoline inventories partially offset by a small upward trend in distillate inventories. Kerosene jet fuel inventory shows no significant trend over the period. While the distillate trend results from a combination of small trends in various reporting segments and is not significant, the gasoline trend is dominated by the reduction of finished gasoline inventory in terminals. The trend has resulted from continued efficiency gains in spite of the requirement to deliver an increasing number of product formulations to meet environmental regulations.

While the overall major light petroleum product inventory trend is not expected to change significantly, discretionary inventories respond strongly to markets and can exhibit significant deviations from the trend line, as shown on Figure 2 for the period from late 1995 through 1998. During 1996, major light petroleum product inventories were near the minimum of their operating range. This was driven by an economic incentive to liquidate discretionary inventory, exacerbated by a confluence of world events that resulted in short-term demands in excess of immediately available refinery production and imports. Beginning in 1997 and continuing through 1998, production and import availability of major light petroleum products exceeded demand, and inventories increased to near the maximum of their operating range, driven by economic incentives that have encouraged the holding of discretionary inventories.

The NPC concludes that over the time period of this study, the petroleum supply system balancing mechanisms available to respond to product market events will not appreciably change. Therefore, the frequency or magnitude of significant (non-crude oil related) upward retail price moves are not likely to increase. This conclusion is predicated on the assumption that no additional regulatory constraints to capacity growth, operational flexibility, or import availability will be implemented.

The conclusion is based on the examination of two petroleum product supply/demand cases (a base case and a high-demand case) and the market mechanisms available to satisfy seasonal demands. In both cases, the same domestic refining distillation and conversion capacity growth is used, based on historical patterns of incremental growth at existing refineries offset by closures of smaller non-economic facilities. The base case demand projection is similar to the product demand growth observed over the last ten years and reflects the impact of cyclical economic activity on overall product demand. The high-demand case assumes product demand growth rates observed over the last five years. This case is designed to test system capability against demand growths reflecting a period of relatively low petroleum product prices and continued economic expansion.

Figure 2. U.S. Major Light Petroleum Product Inventory Trends.



Source of Data: Energy Information Administration.

In the base case, demand and domestic refinery capacity growth are about equal, and no appreciable change in refinery operation, inventory behavior, or import patterns is required to satisfy demands. The high case demands are met through a small increase in domestic refinery distillation capacity utilization, optimization of some refinery yield flexibility, and increased gasoline imports. Inventory behavior and refinery capacity are unchanged. The resultant imports are well within expected Atlantic Basin import supply capabilities, and yield flexibility remains available to respond to unexpected events.

While the analysis assumes specific actions to respond to increased demands, multiple variables impact the marketplace, with U.S. refining capacity utilization and import availability only part of the equation. In reality each company will independently evaluate and respond to supply, demand, and market conditions, based on its own assets, strategies, and capabilities. The result is the aggregate effect of these individual actions.

The focus on distillation capacity utilization as a measure of the ability of the domestic refining industry to respond to changes in the light product supply/demand balance is somewhat misleading. Distillation capacity is the least expensive to debottleneck, and the capacity in place in the United States is primarily determined by the need to keep downstream conversion facilities such as fluid catalytic crackers[1] and cokers[2] operating at capacity. It is primarily the yield flexibility in these conversion units that allows the industry to respond to market signals. As the demand for major light petroleum products has increased, the capacity of conversion units has increased at a much faster rate than the capacity of distillation units. The increased feedstocks required for these conversion units have been provided through a combination of small incremental distillation capacity increases, increased utilization of existing facilities, and the import of feedstocks. While a significant portion of the spare distillation capacity has been utilized, distillation capacity will expand or imported feedstocks will be obtained, as needed, to keep these key conversion facilities fully utilized.

The refining and distribution system provides the flexibility and continuous flow of products necessary to accommodate normal fluctuations in either supply or demand. Geographically unique product specifications have, to a certain degree, decommoditized gasoline in some parts of the United States. This can limit the ability to quickly redirect supply when inventory becomes scarce. Product becomes more difficult to divert from one market to another to meet immediate requirements because it may need to be specifically manufactured, stored, and transported. Industry does not routinely carry inventory to specifically respond to large unexpected events. The costs for continuously maintaining surplus inventories to meet unexpected events would be reflected in permanently higher consumer prices but would still offer only limited protection from upward price changes.

During supply/demand imbalances, except for local occurrences, it is not possible to isolate causality between price and inventory alone, especially on the scale of finished petroleum products in the United States. Nevertheless, as inventories approach the lower part of their operating range, their ability to be used to respond to market imbalances becomes more limited. This increases the probability that a more significant price movement, particularly at the spot and wholesale levels, may occur before the market rebalances.

Inventories and prices are constantly changing in response to a combination of operational and economic factors. The magnitude and speed of these movements are related to the size of the factors and the flexibility of the supply system to respond. While spot and wholesale market prices can move dramatically to signal the need to rebalance supply and demand, retail prices neither rise as fast nor fall as rapidly as spot and wholesale prices. This lagged, dampened consumer price effect is shown in Figure 3, which shows the relationship between the PADD I (East Coast) retail and spot reformulated gasoline price from January 1995 through the middle of 1998. These price swings at the spot and wholesale level provide the commercial signals necessary to obtain a supply response, often before retail price increases become a consumer issue.

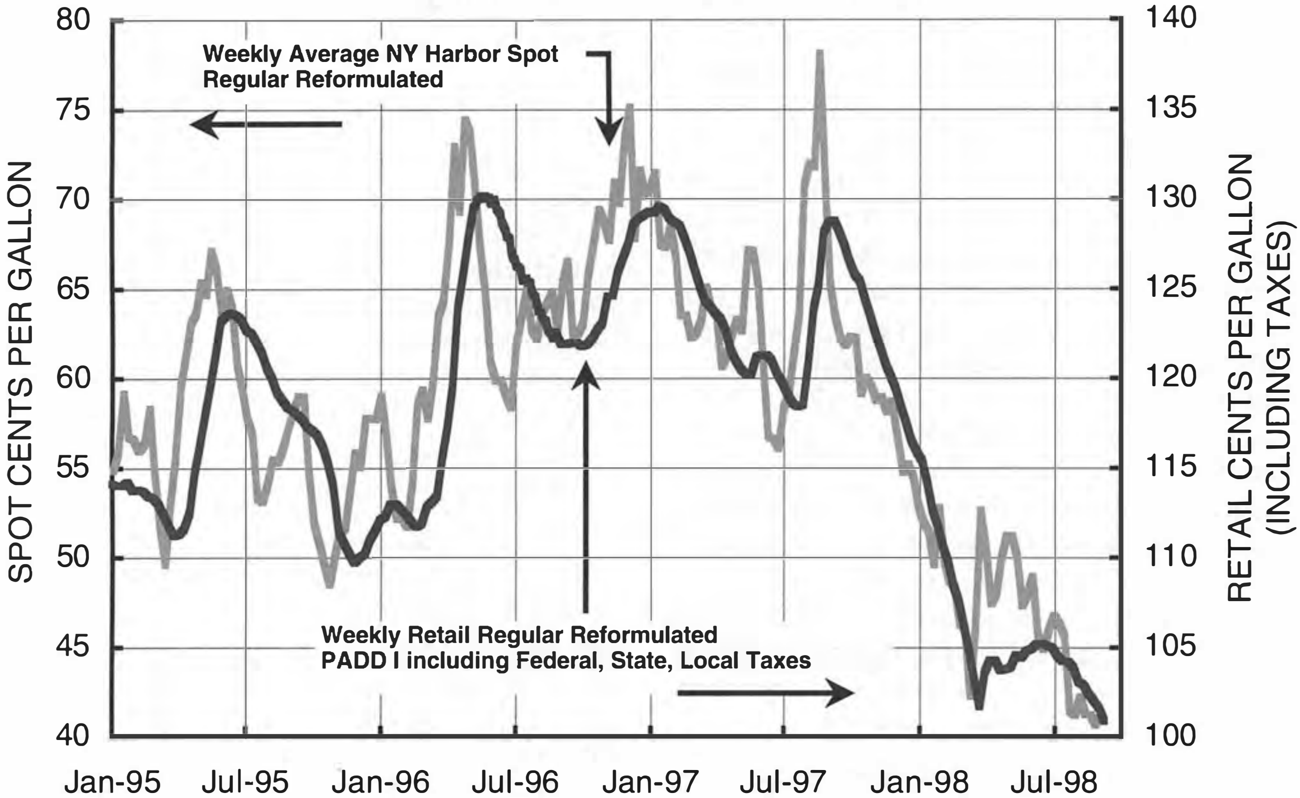
Significant price excursions of major light petroleum products in the United States will continue to be driven primarily by movements in the global price of crude oil. Non-crude oil related upward retail price movements tend to be driven by an infrequent large event or a confluence of smaller events in the same direction.

The petroleum supply system is comprised of a large number of competitive market participants. The competition among these participants provides an incentive for cost-effective delivery of petroleum products to the consumer. Consumers have realized most of the benefits of major system efficiencies achieved over the last

[1] Catalytic cracking is the refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil.

[2] Coking is a process by which heavier crude oil fractions can be thermally decomposed under conditions of elevated temperatures and pressure to produce a mixture of lighter oils and petroleum coke. The light oils can be processed further in other refinery units to meet product specifications. The coke can be used either as a fuel or in other applications such as manufacturing of steel or aluminum.

Figure 3. Lag Between Retail and Spot Reformulated Gasoline Price—PADD I (East Coast).



Source of Data: Energy Information Administration.

several years. As this supply system has evolved, it has demonstrated the ability to respond quickly to disruptive events. Spot and wholesale market signals are critical requirements for efficient delivery and for maintaining supply and demand in balance. Future events will undoubtedly create short-term supply/demand imbalances and may impact the price of major light petroleum products relative to crude oil. The study finds no appreciable change in the ability of market mechanisms to resolve such imbalances. Therefore, the frequency or magnitude of significant (non-crude oil related) retail price moves are not likely to increase.

ANSWERS TO THE SECRETARY OF ENERGY'S QUESTIONS

Question 1a. What are the factors behind the long-term decline in product inventories and is the trend likely to continue over the next few years?

Answers: (1) There has been a modest long-term decline in major light petroleum product inventories, driven by a decline of gasoline in bulk terminals. Inventory levels have deviated from this long-term trend with a significant cycle below and above the trend from 1996 to 1998 in response to market conditions. (2) This long-term trend is the result of improved operating efficiencies partially offset by operational requirements for an increased number of product formulations to comply with environmental regulations. (3) The long-term trend is expected to continue through the time frame of the study as additional operational efficiencies are attained, resulting from continued industry consolidation.

By the fall of 1997, when the Secretary's request letter was transmitted to the NPC, inventories had recovered significantly from their recent lows in 1996 but were still well below typical levels observed in prior periods. In this context, the question concerning a significant long-term decline in inventories and the likelihood of the continuance of the trend seemed appropriate. However, market conditions through the end of 1997 and into mid-1998 encouraged the accumulation of discretionary inventory.

Since holding inventory is a cost, there is an underlying continuous pressure to eliminate that which is not needed to meet customer demand or cannot return a profit to the holder. Without economic incentive, the industry will operate at minimal discretionary inventory levels. Some factor or combination of factors must be in place to drive inventory above minimums—the economics of a seasonal build is a frequently cited example.

Major changes in the seasonal build and draw of gasoline and distillate inventories are not expected. The build and draw of seasonal inventories in the United States is largely a function of the coproduction of distillate during the summer gasoline season and, similarly, of gasoline during the winter. These inventory builds mitigate the requirement for supply from other sources during peak demand periods. The amount of inventory used to balance seasonal demand is largely a trade-off between the cost of additional yield flexibility in refineries and the cost of carrying inventory. While these trade-offs exist, aggregate changes in the refining industry occur slowly.

All else being equal, surplus inventory may act to dampen upward price movements caused by any of the factors that contribute to a regional or local supply imbalance. However, maintenance of non-market-supported discretionary inventory increases price risk and cost for those who hold it. It may also act to accelerate the rate of any downward price transient, exposing the business to added risk.

Question 1b. Were the inventory levels of 1996 an anomaly or a steepening of this long-term decline?

Answer: The low inventories of 1996 were an anomaly.

A confluence of circumstances and events unfolded that exacerbated a low inventory situation and discouraged the needed corrections. The most significant of these were as follows:

- A backwardated market throughout 1995 led to 1996 beginning with the lowest U.S. crude oil and product inventories in nearly two decades.
- An exceptionally long and cold 1995–96 winter increased demand in the Northern Hemisphere.
- Storms in the Caribbean and Gulf of Mexico in late 1995 and early 1996 disrupted both crude oil supply and refinery operations.
- Protracted negotiations between the UN and Iraq created a market expectation of future excess crude oil supply.
- Demand for major light petroleum products reflected a continued strong economy throughout 1996.
- During the autumn of 1996, there was an incentive to export low-sulfur distillate to Europe.

The 1996–98 period demonstrated that the market mechanisms in place since the removal of price controls in 1981 worked under considerable and continuing stress. Despite a period of excessively cold weather, disruptions of refining capacity and uncertainty regarding increased crude oil supply from Iraq, refiners and distributors were able to satisfy all consumer demands. The higher spot product prices stimulated increased production of needed products, which, in turn, led to a calming of markets. This ability of the industry to respond to price incentives with additional product provides a further level of supply security for consumers.

Discretionary inventories will continue to be variable and can move dramatically as market conditions dictate. This study concludes that discretionary inventories approached the minimum of their operating range during 1996 and that by mid-1998 they had approached the maximum of their operating range. Future market conditions will undoubtedly cause these inventories to decline. Whether the market conditions would be sufficiently severe to drive inventories back to their 1996 levels remains to be seen.

Question 2a. In the context of these long-term trends, are minimum operating levels (inventories) still a useful concept for the Department to use as a benchmark or indicator of possible future problems in supplies or prices?

Answer: Minimum operating levels are neither an indicator of supply problems nor are they useful by themselves as a predictor of retail price.

The empirical observation of a "low" inventory level, and the extent to which price increases occur at that level, is a function of several factors. Among these are: (1) location—whether observations are nationwide or regionally specific; (2) supply and demand—ability to identify the extent and duration of an unexpected imbalance in supply or demand; (3) logistics system—dislocations and disruptions in any component of the distribution system; and (4) other price, supply, and demand forces exogenous to the scope of this study.

Consumers may view any rapid upward price movement over a short time frame as a matter of concern. As a method of identifying price events, the NPC has chosen a hurdle of an increase of 5 percent or more in national average retail price over a four-week period. Since 1992, gasoline and distillate exceeded the hurdle eight times, only two of which occurred when inventories were near minimum operating levels. Although there were brief price excursions during these periods, customers were continuously supplied.

But the concept of minimum inventory is useful.

The concept of minimum physical inventory required for the operation of a supply and distribution system is useful in providing an estimate of inventory required for steady-state operation. Inventory is essential to the operation of the supply system, and a minimum requirement is a function of (1) the static physical system requirements such as line fill and tank bottoms; (2) utilization or throughput level, which defines a steady-state "working inventory"; and (3) the extent of departure from ratable demand and/or supply, which requires additional inventory to buffer the resupply cycle in other than steady state conditions. As a practical matter, these minimums are generally estimated from observed data.

It is the conclusion of this study that the confluence of events in 1996 resulted in observed inventory levels being near the minimum of their operating range.

Question 2b. Can the NPC define such levels of inventories (either as minimum operating levels or some other construct) that if not maintained, would cause supply problems; and how do such levels compare to those identified in the 1989 study or the minimum observed inventories now used by the Energy Information Administration?

Answer: The NPC cannot define an inventory level that would be indicative of supply problems in the absence of the context of all other physical and economic factors at any point in time. However, this study has developed a lower operating inventory (LOI) estimate that is similar to minimum operating inventory and minimum observed inventory.

This study recommends replacing both the minimum operating inventory as defined in previous NPC reports and the minimum observed inventory used by the EIA with a newly defined lower operating inventory. LOI is simply a gauge to help assess current inventory levels. When inventories approach LOI, the condition does not indicate an impending supply shortage or retail price swing, but rather a diminished flexibility to supply short-term increases in demand from inventory. This diminished capability must be evaluated along with many other factors before conclusions can be reached. These LOI levels are not materially different, when adjusted for structural change, from those defined in the 1989 NPC report, *Petroleum Storage & Transportation.*

As the petroleum industry infrastructure continues to evolve, LOI levels need to be updated periodically to reflect statistical and operational changes. Between NPC studies, it may be appropriate for the Energy Information Administration, in cooperation with industry statistical committees or consultants, to re-evaluate the LOI estimates as necessary to recognize significant changes.

Question 3. In the context of these apparently permanent lower inventory levels, will capacity limitations in the industry, coupled with demand growth (particularly for middle distillates) diminish the industry's ability to respond to dynamic conditions? Will larger price swings become a more frequent and necessary element of market balancing?

Answer: The inventory reductions in 1996 were event driven and not part of a permanent reduction.

Inventory levels are a combination of a long-term trend and a response to short-term economic and operational drivers. U.S. inventories followed worldwide crude oil and product inventory declines in the 1995–96 period. In 1997–98, they followed worldwide inventories back to higher levels. Thus, while there has been a modest downward trend in U.S. major light petroleum product inventories in the past decade, the decline in inventories that seemed so dramatic in 1996 was the result of short-term factors and not an acceleration of a long-term decline.

Supply system capacity limitations will not diminish the industry's ability to meet expected demand and to respond to dynamic conditions through 2002.

Refinery capacity growth coupled with import availability should maintain the industry's ability to respond to dynamic conditions, assuming no significant changes in the regulatory environment. Capacity increases in 1998–2002 will occur by incremental additions at existing refineries. Moreover, continued availability of gasoline imports is expected to exceed U.S. requirements.

Larger or more frequent product-driven retail price swings are not anticipated in 1998–2002.

Absolute price levels, as well as price changes, are driven by a variety of global, regional, and local market forces. The primary driver of price level is world crude oil price. Even during the relatively "tight" period of 1996, the majority of the price increase in products was driven by the movement in the price of crude oil. Crude oil price events are seldom predictable.

In unbalanced situations, causality between price and inventory is extremely difficult to identify. However, the lower the readily available inventory, the less it can contribute to solving an imbalance. Both changes in crude oil price and price swings from product market events will continue to occur, but based on projections of 1998–2002 U.S. supply and demand, the study has found no reason to expect an increase in the frequency or magnitude of product-driven retail price swings.

CHAPTER ONE

A PERSPECTIVE

GLOBAL COMMODITY

Petroleum is one of the world's most important global commodities. Consumption amounts to approximately 75 million barrels per day. In monetary terms, the world's consumers spend over $500 billion annually on petroleum, roughly 5 percent of total worldwide output valued at market prices. Global inventories have been estimated at 6,000 million barrels of inventory, which is equivalent to over 100 days of global oil output. The dynamics of these global inventories working in tandem with free-market pricing and a competitive industry are critical to industry providing this important commodity to the consumer at an attractive price.

There are a wide variety of both crude oils and petroleum products. Many different types of crude oil are produced all over the world. The United States receives crude oil imports from more than 25 countries. Country of origin, density, and chemical properties such as sulfur content and range of distillation usually classify crude oil. Once delivered to a refinery, crude oils are converted into a wide variety of products to quality specifications demanded by the market.

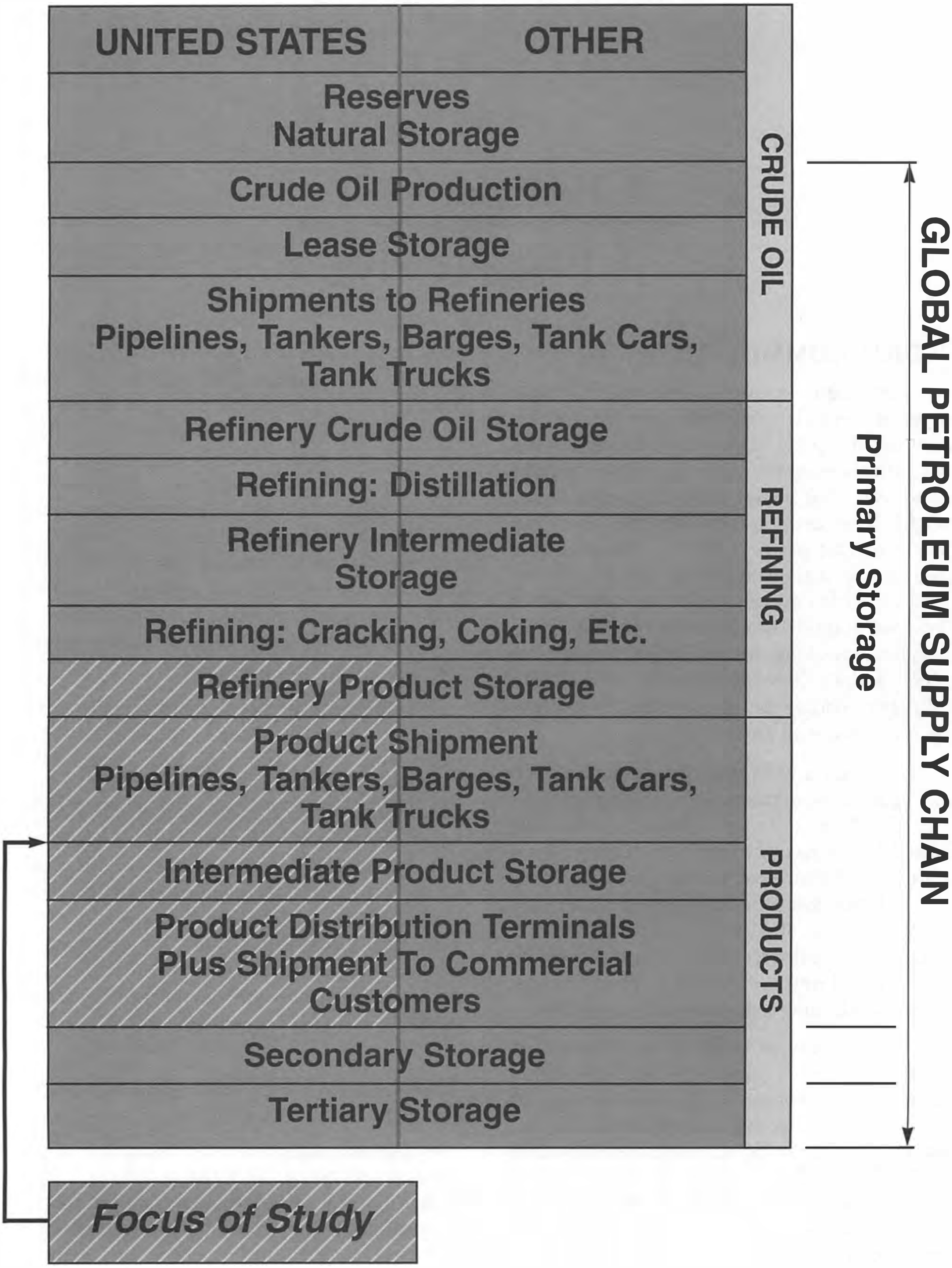
The delivery of products in a timely and efficient fashion is a complex process. The movement of crude oil from its reservoir through the supply chain to become a finished product can take months due to the vast geographies in which crude oil and products travel. Crude oil reserves are generally not located near refineries, and refineries can be far removed from consumers. Significant quantities of petroleum are moved in large ships (some of which hold one-quarter of the U.S. daily gasoline consumption) at speeds around 15 miles per hour. Pipelines flow at the pace of a fast walk, 3 to 6 miles per hour. Even when movements are isolated to the United States, crude oil produced in Texas requires over two months before arriving as product on the U.S. East Coast. In addition to the relatively slow movement of oil, the batched nature of oil movements (crude oils from the well to the refinery and the myriad of products from the refinery to terminals and ultimately to the consumer) creates additional logistical complexity.

Domestic petroleum prices and inventories are directly linked to international petroleum prices and inventories due to the constant ebb and flow of crude oil and finished products from market to market around the world. Petroleum is the world's most economically transportable energy source, a critical factor in the integrated relationship between the United States and the global petroleum markets. The focus of this study, the dynamics of major light petroleum product inventories in the United States, is just one part of the global picture.

THE GLOBAL PETROLEUM SUPPLY CHAIN

The following is a brief discussion of the physical activities in the global petroleum supply chain (Figure 1-1). Movement from segment to segment in the supply chain is generally in batch processes, necessitating operational inventory

Figure 1-1. Global Petroleum Supply Chain.



buffers between each segment to manage the size and the timing of receipts and deliveries.

Crude Oil Production, Gathering, and Field Storage

Production, gathering, and field storage involve the extraction of crude oil from the ground and the accumulation of sufficient inventory to load a ship or truck, or to fill a pipeline batch. As crude oil is extracted from its reservoirs, it is moved via gathering lines and/or trucks and accumulated at storage sites in close proximity to the producing region. Crude oils of differing qualities may be blended to improve marketability and provide a large enough volume to be economically transported to refineries for processing.

Crude Oil Transportation

Crude oil moving from one location to another is labeled "in-transit." In-transit crude oil inventory is an essential part of the global supply system, providing the link between locations where crude oil is gathered and where it is refined. In-transit shipments may be diverted as supply economics dictate, even though in route, providing significant flexibility in crude oil supply. Volumes of in-transit crude oil are much larger than those for in-transit products because of the much greater distance between crude oil gathering and refinery locations than that between refineries and consumers.

Refining

Refining is the process of converting crude oil into finished products. Refineries operate in a continuous mode and therefore require a continuous supply of crude oil. Refineries have crude oil storage facilities located in close proximity to the plants. This storage serves two purposes: (1) as an inventory buffer between deliveries of crude oil and (2) as a site to blend crude oils for cost and yield optimization of processing units. Refineries in the United States have become larger and more complex over the past decade. This complexity is a result of the economics of refining low-quality crude oil and more restrictive product quality specifications.

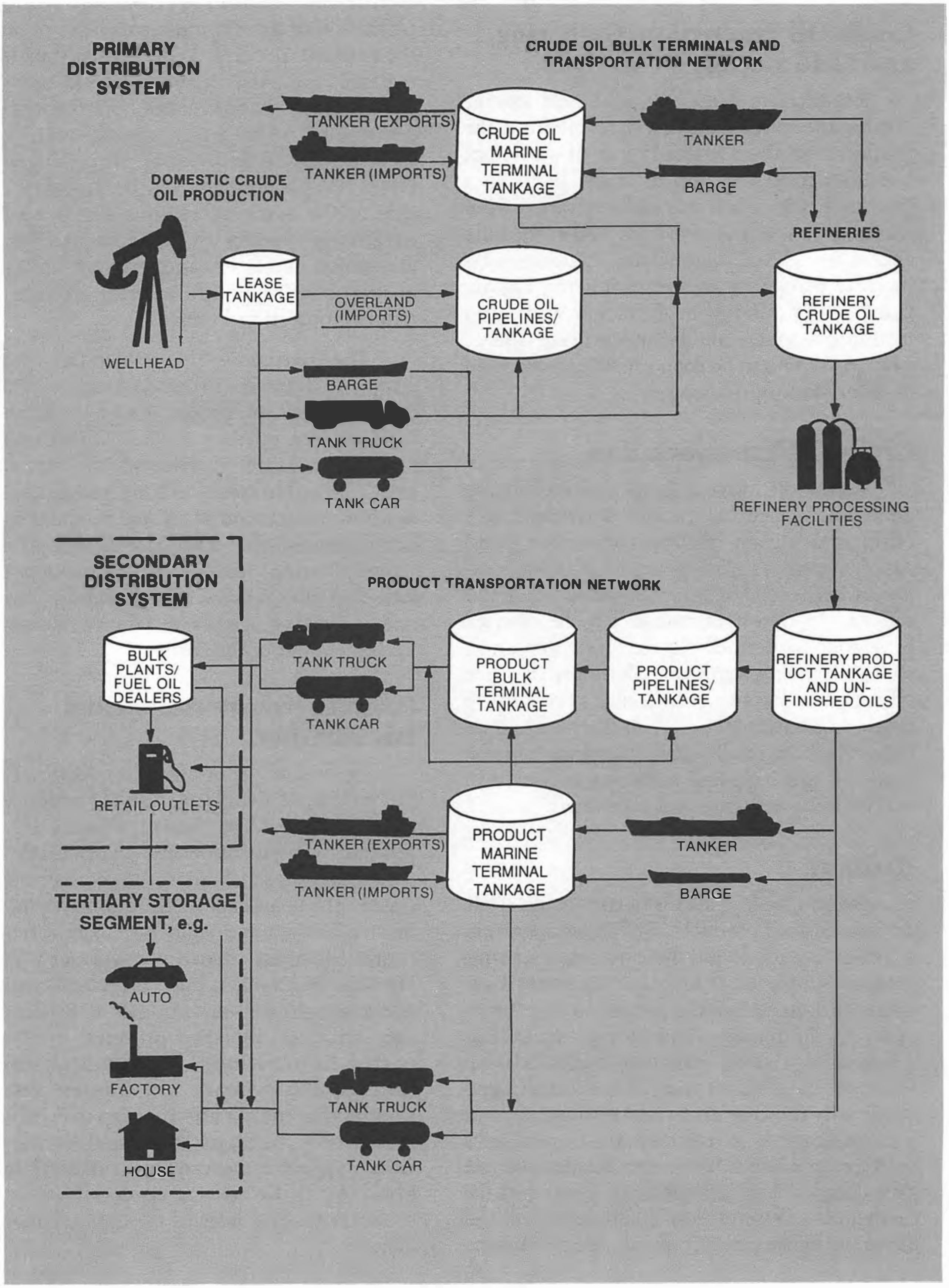
In addition to crude oil, there are other feedstocks and intermediates used in the manufacture of finished petroleum products. Utilization of these components helps optimize the refining process. The majority of these materials are partially processed streams produced on site (intermediates), but refiners may sell or purchase these components as feedstocks to optimize an individual processing unit. Other components that can be produced outside of the domestic refining sector, such as oxygenates, are also used. These materials are also stored in refinery and terminal tankage to enable continuous flow and provide the required operational buffer.

The continuous flow of blending component and finished product streams coming from the refinery process units are delivered into refinery product tanks. This inventory serves as a buffer that allows the transition from the continuous refining process to the batch transportation of refined products to the next destination. The inventory buffer in refinery tankage needs to be sufficient to provide the time required for blending, testing, and protecting against variability of product movement out of the refinery.

Product Transportation and Distribution

Product transportation and distribution is the process of delivering finished products to the marketplace. As shown in Figure 1-2, the product transportation and distribution system is comprised of the primary distribution system, the secondary distribution system, and the tertiary storage segments. The system is comprised of an extensive network of product pipelines and tanker, rail, barge, and trucking operations, as well as terminals and bulk storage facilities. Finished products are transported from refineries in batch quantities through the primary distribution system. Continuous coordination is required between production, transportation, and delivery to ensure supply continuity and value optimization. As in the case of crude oil, in-transit products may be diverted as supply economics dictate.

Figure 1-2. Simplified Diagram of the Petroleum Distribution System.



Primary, Secondary, and Tertiary Inventories

Primary, secondary, and tertiary inventories are terms for the categorization of inventory based on ownership and location within the product distribution system. Storage facilities along the supply chain can be company-owned, leased, or owned by a third party. The U.S. government collects primary inventory data from refiners, pipelines, and large terminals. These data are reported for each facility that has a storage capacity of 50,000 barrels or more or receives products directly by barge, tanker, or pipeline. This storage acts as the inventory buffer between manufacturing the product and supplying the consumer. In addition to the reported primary inventory, at any given moment there are substantial quantities of in-transit petroleum destined for the United States and inventories held in offshore tankage. These volumes are not reflected in U.S. inventory statistics until the petroleum clears U.S. customs.

Petroleum products typically flow in bulk from the primary distribution system into the secondary system before delivery in smaller quantities to consumers. A large portion of secondary product inventories is held at small, wholesale bulk plants that receive product only by tank car or truck. Also included in secondary inventory are products at retail motor fuel outlets, such as service stations, truck stops, and convenience stores, as well as products at retail fuel oil dealers. Tertiary inventories are products held by end-use customers, including agricultural, commercial, electric utilities, industrial, military/government, residential, and transportation. Gasoline and diesel fuel carried in vehicle tanks are also components of tertiary inventory.

Secondary and tertiary inventories were investigated in the 1989 NPC report, *Petroleum Storage & Transportation.* A summary of the data developed in that study for gasoline and distillate is shown in Table 1-1.

Clearly, the secondary and tertiary inventory capacity is significant and plays an important role in the product supply system. During periods of consumer price or supply concern, major quantities of petroleum can be shifted from primary to secondary and tertiary storage. This increases demand on the primary system, depleting available primary inventories at a faster rate than otherwise would occur.

Generally, as with this study, discussions of inventory behavior are based on observations of the primary inventory system. Similarly, demand is calculated from the sum of supply plus changes in primary inventory, not from actual end-use consumption. As a practical matter, few alternative methods exist. However, changes in the inventories outside of the reporting system can significantly impact both the perceived and the real abilities of the primary system to satisfy market demand, particularly over short time periods.

TABLE 1-1

**1989 NPC PETROLEUM STORAGE & TRANSPORTATION STUDY
ESTIMATED INVENTORY AND STORAGE CAPACITY
OF THE PETROLEUM DISTRIBUTION SYSTEM
AS OF MARCH 31, 1988**

	Inventory				Capacity			
	Primary	Secondary	Tertiary	Total	Primary	Secondary	Tertiary	Total
Gasoline	231	48	63	342	451	92	109	652
Distillate	89	15	113	217	261	37	255	553

PETROLEUM INDUSTRY FINANCIAL ENVIRONMENT

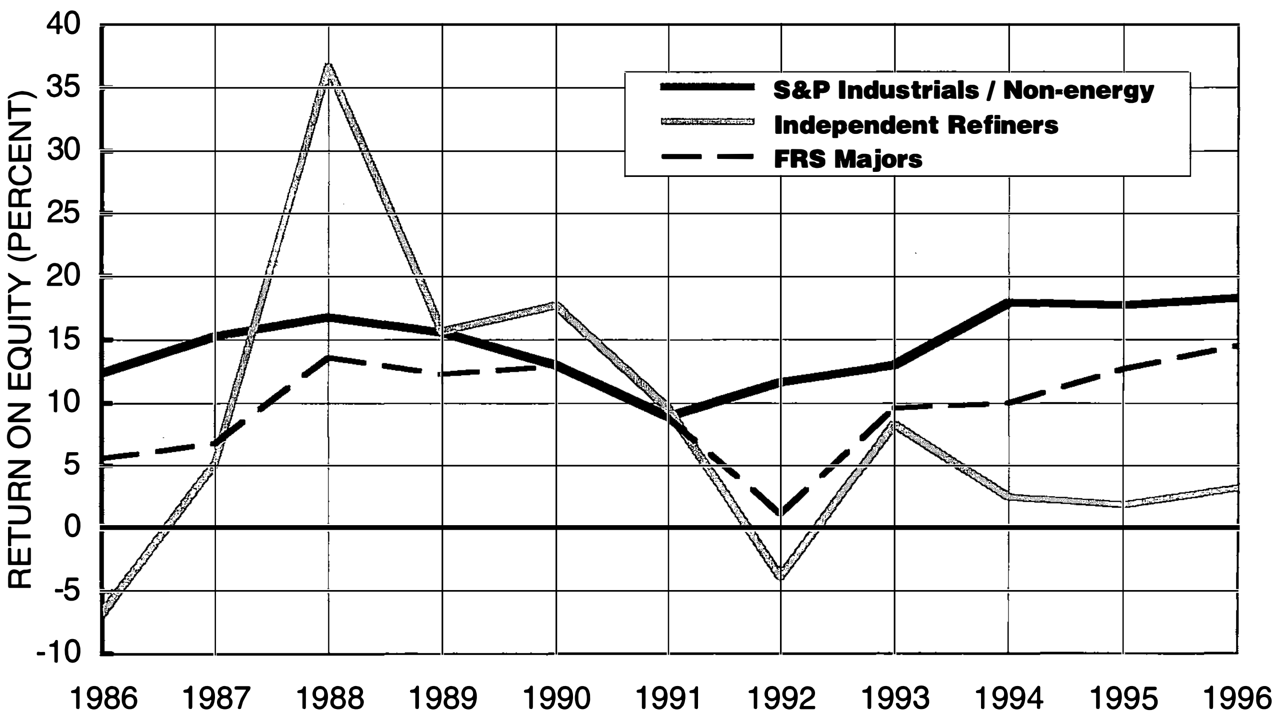
The financial environment for the downstream segment of the U.S. petroleum industry is not expected to change significantly. Contrary to general perception, profitability relative to other industries has been substandard in the petroleum business as a whole and particularly poor in refining and marketing. Figure 1-3 shows that the annual return on equity (ROE) for the FRS major petroleum companies[1] has been consistently below that of the non-energy industrial companies in the S&P 500 since 1986. The ROE performance of U.S. independent refiners has also been plotted as an indication of results in the refining and marketing sector. This line illustrates the poor results for the non-integrated downstream segment of the petroleum business. Figure 1-4 shows the financial underperformance of the FRS major petroleum companies' refining and marketing businesses relative to their overall profitability. While the petroleum industry generates large cash flows and profits, by any measure it is a high-volume, low-margin business. The continuous poor profitability of the downstream relative to other segments of the petroleum business has resulted in a large number of refinery closures and an increased focus on actions to improve performance for those remaining in the business.

Usually, low profitability leads to less investment in a business segment, not more, as companies direct their financial resources to maximize returns to their shareholders. However, investment in the downstream rose in the early 1990s, peaking in 1992, as companies weighed stay-in-business investments required to meet environmental regulations against the asset sales values and high costs of shutdown.

At the same time companies were investing in refineries, commoditization of the petroleum product market resulted in significant changes in the way petroleum products were valued at the spot and wholesale levels. The new market

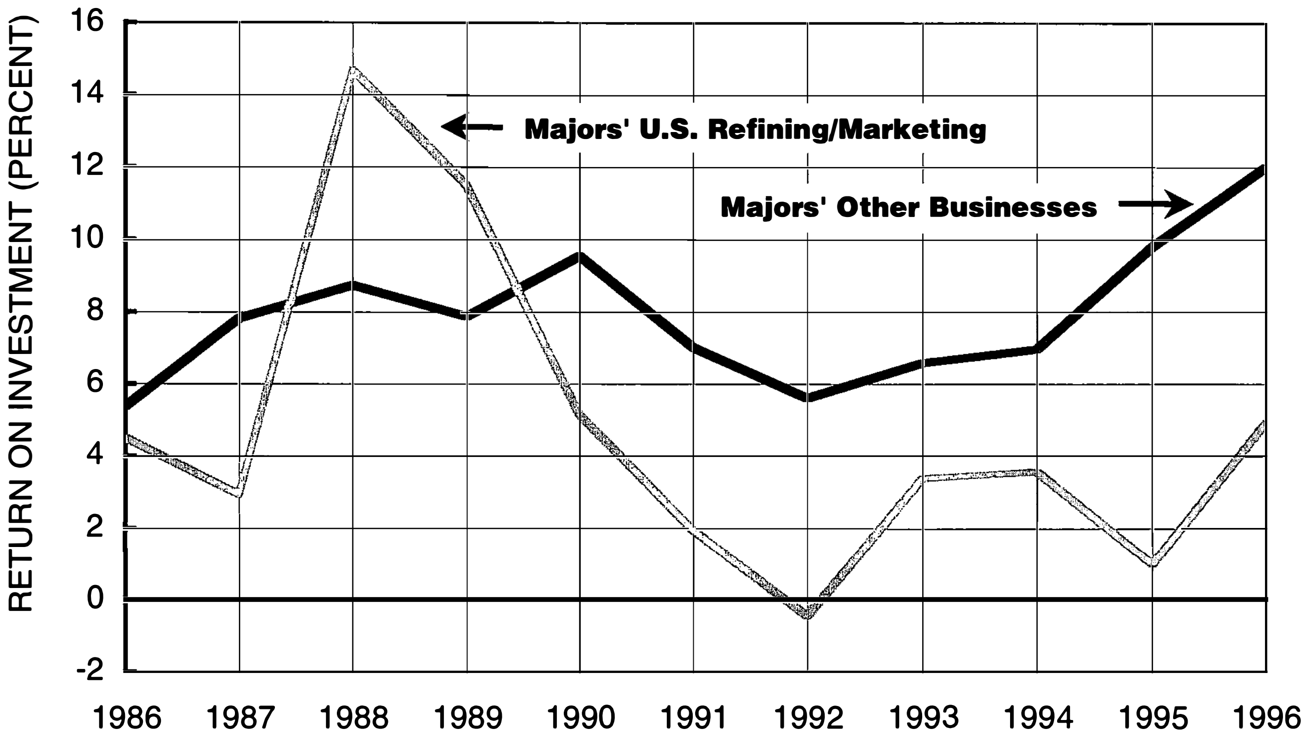
[1] Energy Information Administration's (EIA's) Financial Reporting System (FRS) of the two dozen or so U.S.-based major energy-producing companies.

Figure 1-3. Annual Return on Equity for FRS Petroleum Majors, Independent Refiners, and U.S. Industry.



Source of Data: Energy Information Administration.

Figure 1-4. FRS Petroleum Majors' Return on Investment in U.S. Refining/Marketing and All Other Lines of Business.



Source of Data: Energy Information Administration.

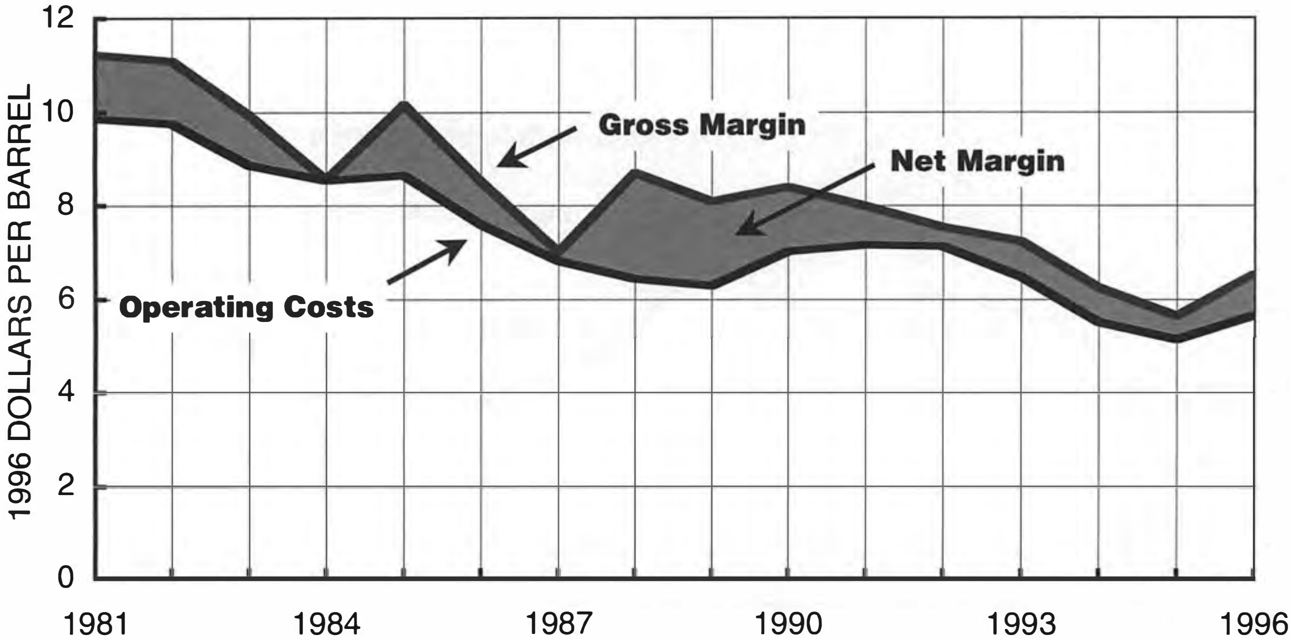
structure resulted in forward price transparency and the opportunity for price risk management for both large and very small companies, such as heating oil dealers. This change also allowed market participation for competitors without either capital investment in downstream infrastructure or environmental exposure.

As with other U.S. industries, oil company strategies to improve financial performance since the mid-1980s have included consolidating, restructuring the asset base, focusing on core business competencies, outsourcing, and divesting poorer performing non-strategic assets. The average refinery distillation capacity utilization grew from 83 percent in 1986 to 95 percent in 1997, contributing to a reduction in unit costs. Overall operating costs have continually been reduced (Figure 1-5).

Margins drive profitability in the downstream business. Gross refining margins (the simple spread between raw material cost and the refined product price received) and net margins (gross margin less operating costs) are key indicators of the financial performance of the U.S. refining and marketing business.

- Gross margins have been on a continuous decline since 1985, dropping over $4.50 per barrel, or about 40 percent.
- The industry has reduced operating costs by $4.20 per barrel, a similar 40 percent.
- Downstream net margins have been below $2 per barrel since 1981, excluding the two strong years of 1988 and 1989. These are the only two years in which petroleum downstream return on investment was not lower than the average of other U.S. industries.
- Capital investment required to stay in business and high barriers to exit (both largely driven by environmental regulation) have contributed to the underperformance of downstream refining and marketing assets. As a result of the highly competitive petroleum products market, environmental investments have not

Figure 1-5. FRS Companies' Refining/Marketing Margins and Operating Cost.



Source of Data: Energy Information Administration.

resulted in product price increases that reflect the full cost and return on investment. However, because of the high cost of exit, these investments continue to be made. Additional environmental legislation generates concerns over significant additional capital investment requirements, with little or no promise of improved profitability.

- Competition has resulted in the consumer realizing essentially all of the cost reductions achieved in the downstream petroleum business.

The pressure to improve financial performance extends beyond refineries. Product distribution terminals have also seen the elimination of underperforming assets. Market transparency, efficiency, and the resulting shrinking margins have resulted in the disappearance and consolidation of oil traders and other middlemen. Retail market competition not only from traditional marketers but also from a significant number of new participants has resulted in an increased focus on retail strategies and core areas of competitiveness. All of these have streamlined the system and served to reduce inventory.

THE ROLE OF INVENTORY IN THE U.S. PRIMARY SUPPLY SYSTEM

At the end of 1997, U.S. reported primary petroleum inventories totaled 1.6 billion barrels. These inventories, which are only a portion of the total quantity of oil actually held in inventory, play several important roles in the efficient, economic delivery of crude oil from leases to refining centers and oil products from refining centers to end-use markets. Petroleum is relatively easy and inexpensive to store. These characteristics provide an alternative to investment in manufacturing and production facilities to meet the moment-to-moment variations in consumer demand. Over time, the petroleum supply system has evolved using inventories as a mechanism to achieve high utilization of capital facilities. For example, EIA data indicate that U.S. refineries operated in excess of 90 percent of their crude oil nameplate capacity in 1997. In contrast, the domestic electric power industry meets short-term demand changes through production because electricity is difficult and expensive to store. Consequently, the electric power industry operated at about 50 percent of nameplate capacity in order to have sufficient capacity to meet peak demand.

Inventory as an Operational Necessity

Under normal circumstances, the flow of crude oil and products around the world is not always constant, homogenous, or uninterruptable, due in part to the batch nature of some movements. One function of petroleum inventory is that of an operational buffer between supply and demand. This role requires sufficient inventory to allow the supply system to operate efficiently. Inventory provides the interface between each segment of the industry's supply chain of production, transportation, refining, product distribution, and marketing. This inventory allows the supply system to balance different rates of flow in different parts of the system. Inventory used as an operational necessity includes tank bottoms, pipeline fill, in-transit inventory, and working inventory. This inventory is normally not available to meet demand, as it is required to maintain a stable operation. As the industry achieves higher throughput rates without adding significant new infrastructure, improved operational efficiency is represented by a reduction in the apparent days of supply of inventory. While this number reflects improvements in efficiency, it does not reflect a lower level of supply reliability.

Inventory as a Component of Supply

Inventory as a component of supply includes inventory above that required as an operational necessity, but does not include discretionary inventory held strictly as a financial opportunity. This inventory includes allowances for seasonality, random variability in the logistics system and customer demand, maintenance allowances, and other considerations. This inventory is produced and stored in order to meet expected future demand. Product demand has seasonally and regionally specific characteristics. Off-season storage of inventory may serve as an economic method of supplying future demand versus a more timely purchase or production increase. In the United States, heating oil is the product that has historically been the most dependent on seasonal inventory builds to supply periods of peak demand. Companies also build inventories in preparation for planned maintenance in the production, refining, and logistical systems. To ensure that customer needs are met, additional inventories are normally held as protection against variability in both the elements of the supply chain and in demand. It should be emphasized that the quantity and use of these inventories do vary and are subject to individual company operating philosophy.

Inventory as a Financial Opportunity

Physical inventories can also be used to improve economic performance. Inventory held for this purpose is referred to as "discretionary" because it is in excess of the level necessary for operational efficiency. This capability is, to varying degrees, available in all segments of the supply chain: production, refining, terminaling, commercial end-use, and consumers. In the primary sector, these inventories appear predominantly in terminals. Most participants actively manage their physical product inventory in response to economic incentives.

Major oil products in the United States have spot prices for both current and future delivery. During some market conditions, an oil product can be purchased today and sold in the forward market for more than the cost of storage. During these market conditions, inventories generally build. Similarly, forward markets may not support the cost of storage, and under these circumstances inventories generally draw. These dynamics are an important part of the ongoing balancing process that ultimately matches crude oil production to the end-use demand of a wide variety of petroleum products. Inventory is a cost similar to other costs embedded in the petroleum production and distribution system. At a minimum, inventory cost equals the carrying cost of the inventory working capital. This cost is a function of the value of the stored oil and the interest rate, as shown in Table 1-2.

TABLE 1-2

MONTHLY INVENTORY CARRYING COST (Cents/Barrel/Month)

Interest Rate (% per Year)	Oil Value (Dollars/Barrel)			
	$10	$15	$20	$25
6	5	8	10	13
8	7	10	13	17
10	8	13	17	21

In general, inventory carrying costs are low relative to the value of the oil itself, but are still significant. At $15 per barrel and a discount rate of 10 percent per year, the annual cost of holding a million barrels of inventory is $1.5 million. Total primary inventory in the United States (including the Strategic Petroleum Reserve) is about 1.6 billion barrels, resulting in annual primary inventory carrying costs of over $2 billion. In addition to carrying charges, a cost of storage is also incurred when inventory is held. Commercial fees typically average between 15 cents and 25 cents per barrel per month for crude oil and 30 cents to 40 cents per barrel per month for gasoline and distillate. The competitive nature of the major light petroleum product market drives companies to operate at an efficient, economic inventory level, considering both the cost of storage and the need to supply customers under normal supply/demand variability.

While there is a clearly definable cost to hold inventory, there is an obvious offset—the inventory value to the owner. Generally, value is much more difficult to assess than cost. For example, costs for the Strategic Petroleum Reserve can be calculated in a fairly simple manner. However, quantification of the benefits is a much greater challenge. In the United States, the data clearly show that inventory is used to provide additional gasoline supply into the market when gasoline reaches its peak demand in the summer and to provide additional distillate supply into the market when distillate demand peaks in the winter. This pattern, which is the result of the cumulative behavior of a large number of participants in a very competitive market, suggests that the inventory value generally helps offset the associated cost to meet the peak needs in these two seasonal markets.

Inventory as Protection against a Worldwide Emergency

A significant portion of the world's petroleum inventory is tied up in compulsory inventories. Most governments of leading industrialized countries mandate minimum levels of petroleum inventories at some point in the supply chain due to national security concerns, or requirements for membership in organizations such as the International Energy Agency and the European Economic Union.

The United States' Strategic Petroleum Reserve is the largest government crude oil stockpile. It was started in 1975 as part of the Energy Policy and Conservation Act. The Strategic Petroleum Reserve reached a high of 591 million barrels in 1995 and currently contains 563 million barrels, accounting for about 40 percent of U.S. primary petroleum inventory. The industry remains strongly supportive of holding these inventories for use during significant supply disruptions.

THE MAJOR LIGHT PETROLEUM PRODUCT MARKETS IN THE UNITED STATES

Demand

The United States accounts for about 25 percent of the world petroleum demand and is by far the largest consuming country. In 1997, over 70 percent of U.S. demand was for major light petroleum products: gasolines, 43 percent; low-sulfur distillate, 12 percent; high-sulfur distillate, 7 percent; and combined kerosene and kerosene jet fuel, 9 percent. The remainder was predominantly naphtha, petrochemical feedstock, liquefied petroleum gas, and heavy byproducts such as asphalt and coke.

The regional breakdown of petroleum product demand by Petroleum Administration for Defense District (PADD) is displayed in Figure 1-6. The five PADDs shown in this figure are consistent with the following broad geographic U.S. regions: PADD I—East Coast; PADD II—Midwest; PADD III—Gulf Coast; PADD IV—Rocky Mountains; PADD V—West Coast. The demands shown in the figure were derived from the Energy Information Administration's "product supplied" data and represent demand on the primary system. Of particular note, 65 percent of major light petroleum product demand is in PADDs I and II. Also noteworthy is the level of gasoline demand relative to other products. Transportation fuels are the major growth market for the major light petroleum products. Another key market segment is the seasonal residential heating oil market in the Northeast, consuming well over 80 percent of the nation's heating oil.

Gasoline is the most commonly used petroleum product among U.S. consumers. From 1987 to 1997, gasoline demand grew at an annual average rate of 1.2 percent.[2] The gasoline market continues to be extremely competitive, with no one company dominating market share. A variety of gasoline grades are supplied to meet federal, state, and local environmental standards.

A number of different distillate products are produced for a wide variety of end-users. These various products are generically referred to as distillate fuel oil. Regulations require a sulfur content of less than or equal to 0.05 percent sulfur (low-sulfur diesel) for on-highway use. Low-sulfur diesel may be substituted for high-sulfur distillate, but environmental regulations prevent the reverse. The EIA categorizes distillate consumption by the end-uses indicated in Table 1-3 with their respective market shares.

On-highway distillate consumption at over 50 percent of the market is by far the largest portion and has experienced an annual average growth of over 4 percent since 1986.[3] The second largest market share is residential or home heating oil at about 12 percent. This is a highly seasonal heating fuel, with 80 percent of its U.S. consumption in PADD I. Demand is dependent on the length and intensity of cold winter weather. Heating oil inventories normally are at their highest levels in the fall and draw to their lowest levels each spring.

Kerosene and kerosene jet fuel markets are dominated by the aviation fuel sector, which has grown at 3.4 percent per year since 1986.[4] Some of the increase resulted from the phase-out of naphtha jet fuel, which is no longer used by the military. Major consumers of jet fuel include the military, commercial passenger and cargo airlines, and private aviation. Kerosene demand is approximately 3 percent of the kerosene and kerosene jet fuel category.

Demand seasonality is exhibited in gasoline and distillate markets, which account for about 87 percent of major light petroleum product demand. These demands are seasonally opposite, smoothing the total petroleum demand placed on the supply system. This inverse relationship is displayed in Figure 1-7.

Supply

Supply is primarily comprised of refinery output, imports, and inventory change. U.S. refinery outputs supplied about 97 percent of the major light petroleum products in the United States during 1997 (although the United States imports over half of its crude oil supply). The U.S. refining industry continues to evolve toward fewer and larger facilities, as less-efficient refineries are closed. In 1986, there were 219 refineries with atmospheric crude oil distillation capacity of 15.5 million barrels per day. In 1997, there were 164 refineries with atmospheric crude oil distillation capacity of 15.4 million barrels per day.

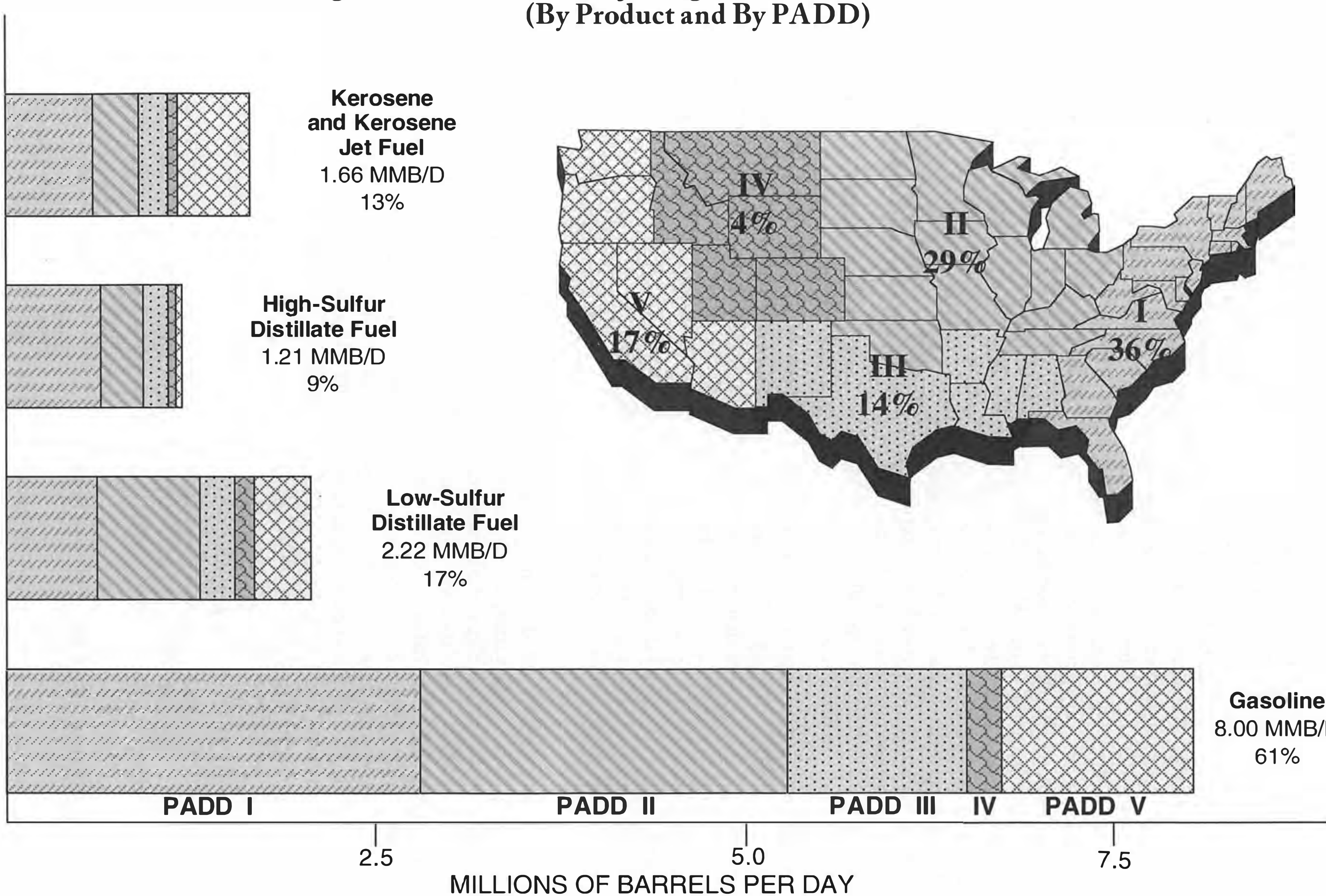
The product transportation infrastructure has changed little since the 1989 NPC report, *Petroleum Storage & Transportation*. Within the

[2] Energy Information Administration, *Petroleum Supply Annual 1997*, DOE/EIA-0348(97), Table S-4.

[3] Energy Information Administration, *Fuel Oil and Kerosene Sales 1997*, DOE/EIA-0535(97), Table 4.

[4] Energy Information Administration, *Petroleum Marketing Annual 1997*, Prime Supplier Sales Volumes of Distillate Fuel Oils and Kerosene, Table 50.

Figure 1-6. 1997 U.S. Major Light Petroleum Product Demand. (By Product and By PADD)



Source of Data: Energy Information Administration.

TABLE 1-3

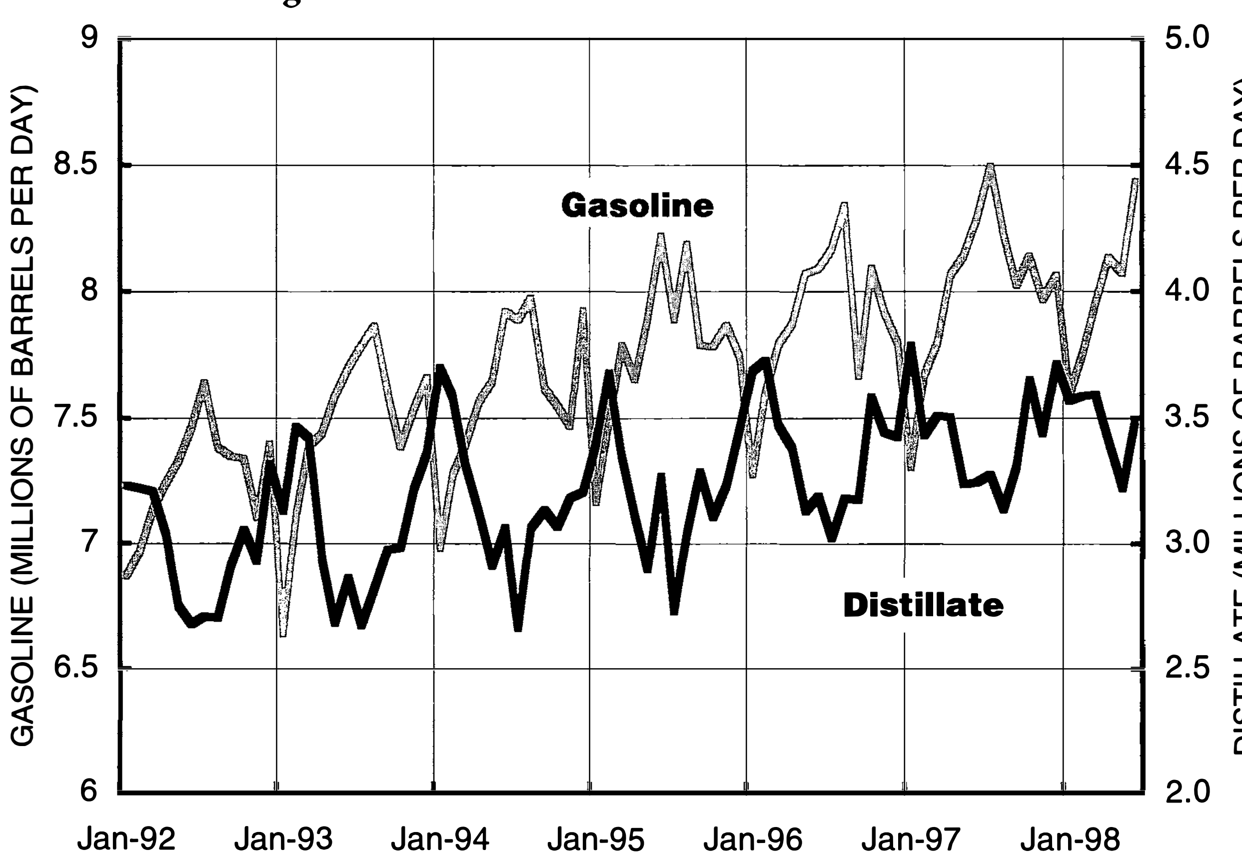
DISTILLATE MARKET SHARE BY END-USE

End-Use	Demand	End-Use	Demand
On-highway	53%	Railroad	6%
Residential	12%	Commercial	6%
Industrial and off-highway	8%	Vessel Bunkering	5%
Farm	6%	Military, Electric, and Oil	4%

Source of Data: Energy Information Administration, *Fuel Oil and Kerosene Sales 1997.*

continental United States, there are two tightly integrated major product distribution systems, PADDs I–IV and PADD V, that have limited ability to interchange products. Pipelines, complemented by marine movements, are the economic transportation options for long-haul, large-volume deliveries. The major petroleum product flows between PADDs take place in an extensive net-work of interregional pipelines. Complementing this system are extensive intra-PADD common carrier and proprietary (non-tariff-regulated) pipelines. These deliveries generally are received in product terminals, which provide the necessary inventory buffer

Figure 1-7. Gasoline and Distillate Seasonal Demand.



Source of Data: Energy Information Administration.

between large receipts and the smaller parcels delivered into the secondary distribution system. Economies of scale drive debottlenecking and facility sharing to accommodate increased transportation and distribution needs as opposed to construction of large new systems. Short-haul and smaller volume movements are by truck and rail.

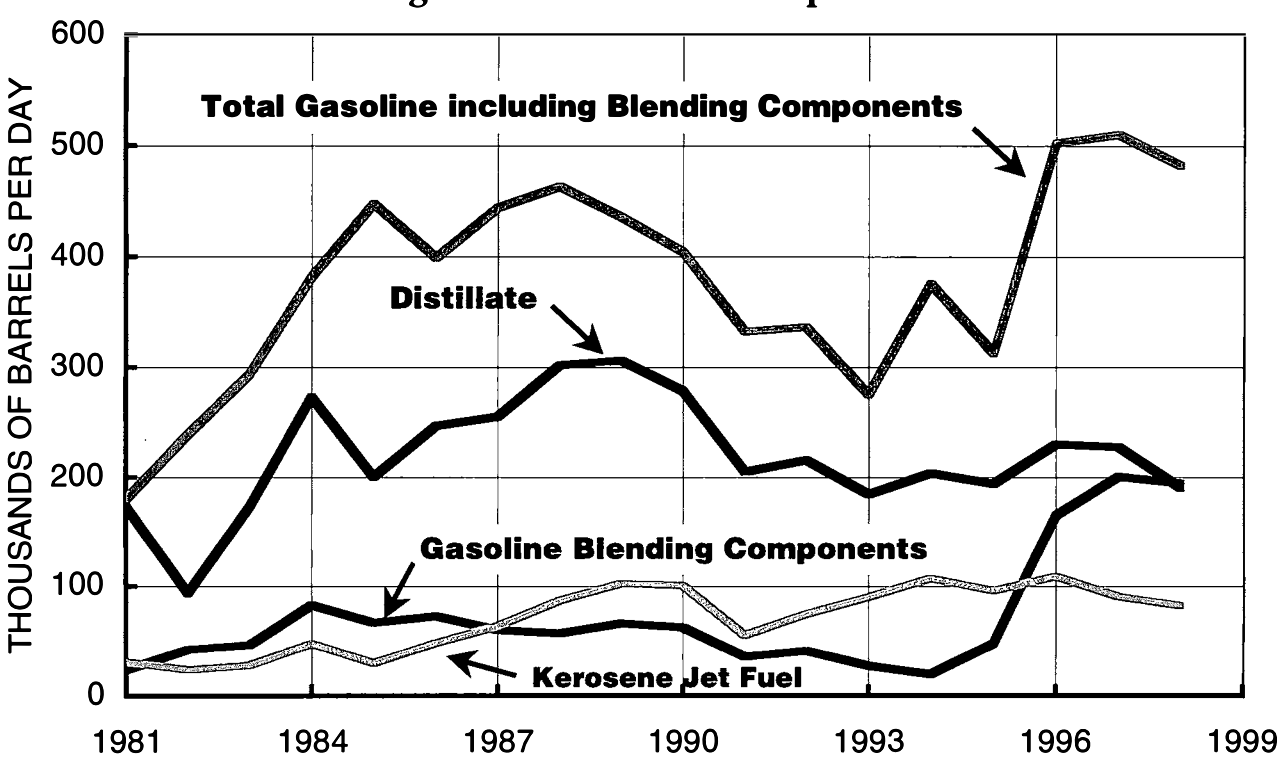
The East Coast (PADD I) depends heavily on other regions for supply, and accounts for most of the nation's imports of gasoline, distillate, and kerosene jet fuel. In 1997, it produced about 35 percent of its own gasoline, received 55 percent from other PADDs, and imported about 10 percent. About 20 percent of the PADD I gasoline production is based on imported gasoline blending components. This region produces about one-third of its distillate needs, imports about 16 percent, and receives more than 50 percent from other PADDs. PADD I only produced about 16 percent of its kerosene jet fuel needs in 1997 and imported about 14 percent from outside the United States, with the remainder coming from other PADDs.

PADD II produced about 80 percent of its own gasoline and distillate requirements and about two-thirds of its jet fuel needs, receiving most of the rest from PADD III. PADD III is a major supply center for both PADDs I and II, producing much more than it consumes. PADD IV consumed less than 4 percent of the nation's finished products in 1997 and produces much of its own needs.

PADD V contains the western portion of the continental United States, Alaska, and Hawaii. PADD V is costly to supply from other U.S. supply centers and is a long distance from world petroleum product export centers. In addition, some regions within PADD V require unique environmental product specifications. As a result, PADD V is largely self-sufficient in refining capacity.

While product imports do not supply a large share of U.S. petroleum demand, they are important regionally. Over 90 percent of U.S. major light product petroleum imports are into PADD I. Figure 1-8 indicates the historical import levels for each of these light products.

Figure 1-8. U.S. Annual Imports.*



1998 data include only January–June.

Source of Data: Energy Information Administration.

PADD I kerosene jet fuel imports have grown steadily. In contrast, gasoline and distillate imports increased rapidly during the 1980s, peaked in 1988, and fell at an equally rapid pace from 1988 to 1991. Since 1991, distillate imports have averaged about 200 thousand barrels per day (MB/D). Beginning in 1995, imports of gasoline blending components increased significantly, rising from 20 MB/D in 1994 to 200 MB/D in 1997. This increase coincides with the beginning of the reformulated gasoline (RFG) program and likely results from the import of RFG blendstocks, which require only oxygenate addition to become finished gasoline.

Most of the major light petroleum product imports come from the Virgin Islands, Venezuela, and Canada. Table 1-4 shows the combined finished gasoline, kerosene jet fuel, and distillate imports from these countries from 1993 through 1997. These three countries provide about 80 percent of kerosene jet fuel imports, nearly all of distillate imports, and about two-thirds of gasoline imports. Europe supplies most of the remaining gasoline imports (approximately 20 percent of the total). The Netherlands Antilles is a significant supplier of kerosene and kerosene jet fuel imports (approximately 15 percent).

Inventory provides an economic option for responding to seasonal demand patterns and reduces required refinery flexibility. During the peak summer gasoline season, distillate production normally exceeds demand and distillate inventory increases. This inventory is normally drawn in the winter to help satisfy peak distillate demand (Figure 1-9). The relationship among primary distillate demand, inventory, and weather is shown in Figure 1-10. Gasoline is normally overproduced during the winter when distillate production is at its maximum. This excess production is generally stored to provide supply during the normal spring refinery maintenance period (Figure 1-11).

Historically, inventories help to meet the peak demand of both products, but play a much larger role in meeting peak distillate demand than they do for meeting gasoline demand. From 1991 through 1997, distillate inventory met on average over 8 percent of U.S. peak winter distillate demand, versus gasoline inventory, which was only used on average to meet 2 percent of peak demand.

MAJOR REFINING AND MARKETING CHANGES

The supply and distribution system for major light petroleum products has continued to evolve over the last decade. The more significant factors impacting the evolution are underlying demand, the implementation of new

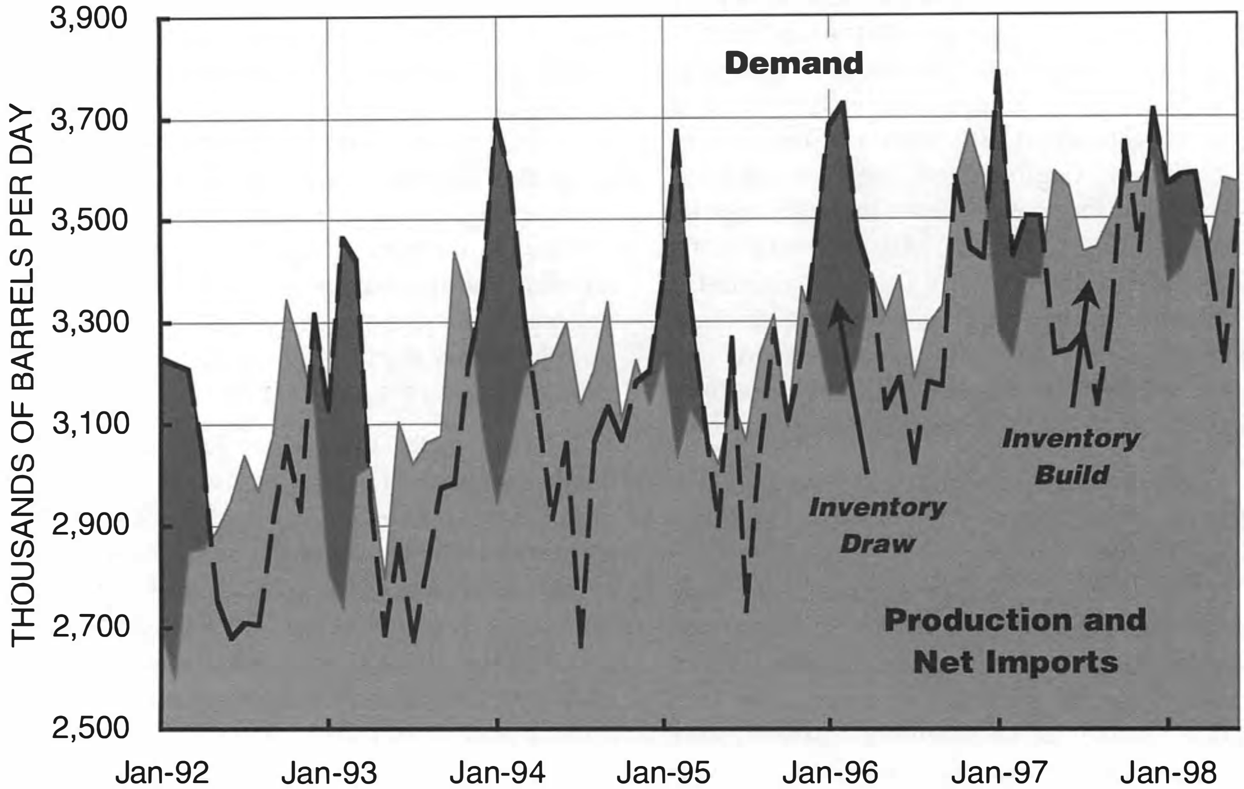
TABLE 1-4

TOTAL IMPORTS OF FINISHED GASOLINE, KEROSENE JET FUEL, AND DISTILLATE (Thousand Barrels per Day)

	1993	1994	1995	1996	1997
Canada	95	94	113	163	140
Venezuela	154	124	130	145	132
Virgin Islands (U.S.)	137	230	190	201	217
Subtotal	386	448	433	509	489
Total Import	515	631	532	647	582
Percent of Total	75%	71%	81%	79%	84%

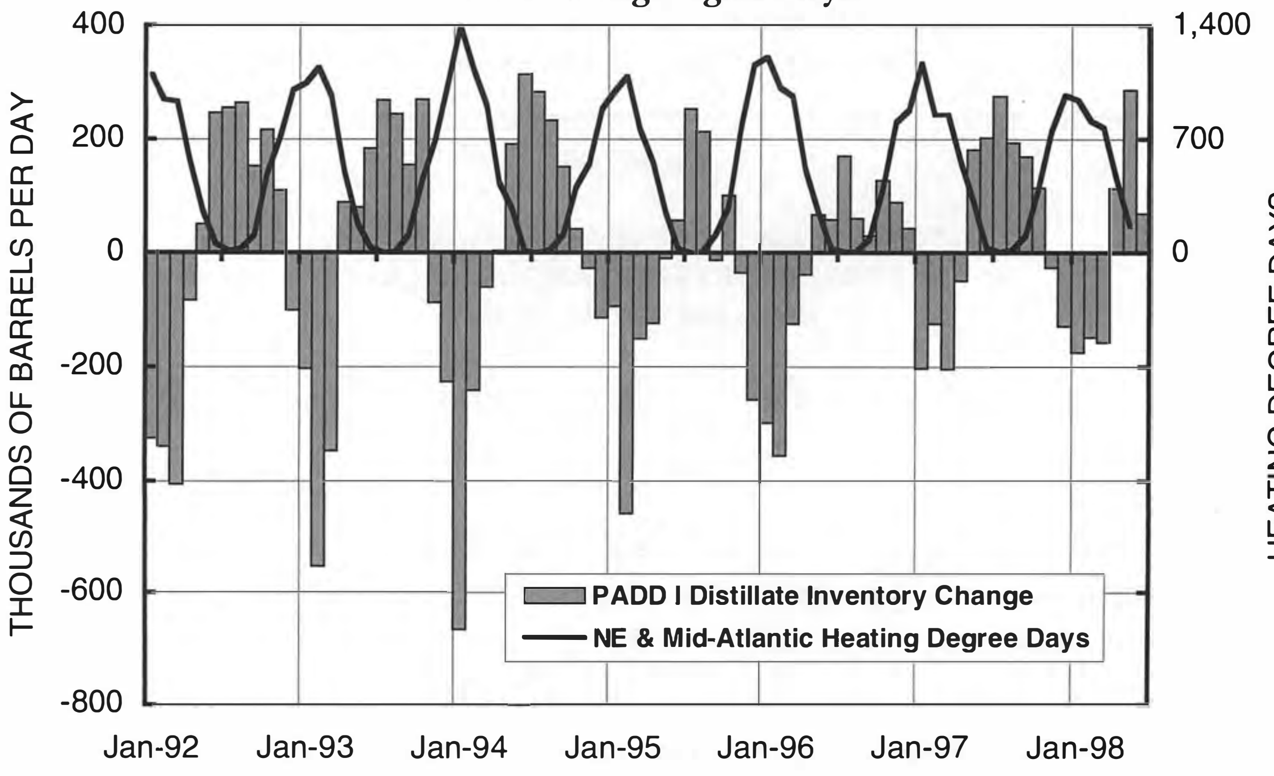
Source of Data: Energy Information Administration.

Figure 1-9. Distillate Seasonal Demand and Production.



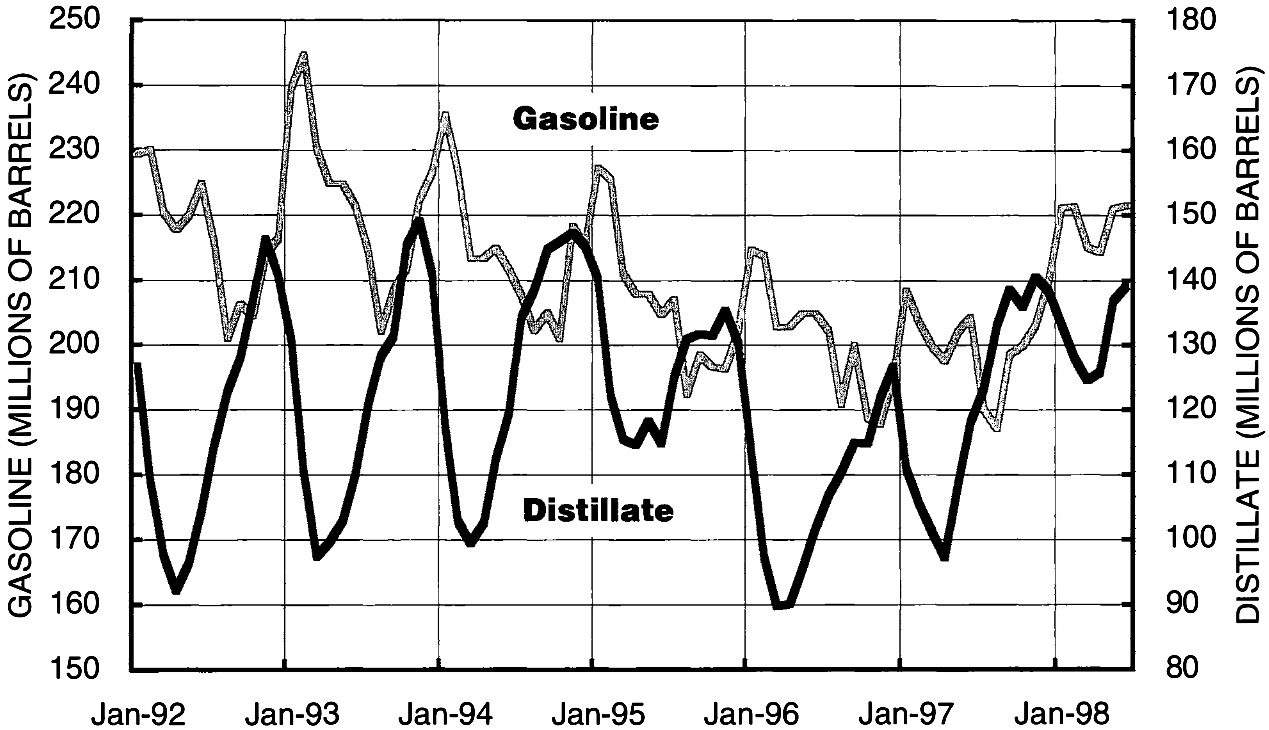
Source of Data: Energy Information Administration.

Figure 1-10. PADD I Distillate Inventory Changes and Heating Degree Days.



Source of Data: Energy Information Administration.

Figure 1-11. Gasoline and Distillate Seasonal Inventory Patterns.



Source of Data: Energy Information Administration.

environmental regulations, and the industry response to the low profitability and competitive nature of the petroleum refining and marketing business. The inventory effect of each individual change can be gradual as trends in operations change, or it can be more pronounced as regulatory changes are implemented or as significant assets are added or removed. Observed industry inventory trends reflect the net result of all of these changes.

Demand Growth

Demand growth for major light petroleum products has averaged 0.6 percent per year from 1978 through 1997. Of the 1.3 million barrels per day total growth, kerosene jet fuel has been the fastest growing and accounts for over half. Gasoline demand increased 0.6 million barrels per day, and distillate demand in 1997 was essentially the same as in 1978. The overall growth pattern is the result of four distinct periods of demand trend:

- 1978 to 1983—Demand fell by almost 1.6 million barrels per day, mostly in gasoline and distillate as a result of ongoing efficiency gains, the high prices following the Iranian crisis, and the economic recessions in the early 1980s.
- 1983 to 1989—With the oil price collapse in the early 1980s and continuous economic expansion, demand grew 1.6 million barrels per day from 1983 to 1989. About half of the growth was in gasoline, with the remainder split equally between distillate and kerosene jet fuel.
- 1989 to 1991—Demand again fell about 0.4 million barrels per day as a result of the slowing of economic growth and some Gulf War effects.
- 1991 to 1997—Since 1991, demand growth has been fairly strong, averaging 2.3 percent per year. While gasoline has the overall slowest growth rate at 1.8 percent per year, it has shown the largest absolute growth of over 0.8 million barrels per day. Distillate has been growing at a rate of 2.7 percent per year and grew by 0.5 million barrels per day. Kerosene jet fuel is the fastest growing, at 3.6 percent per year, and increased 0.3 million barrels per day.

Environmental Regulations

Environmental regulations have affected the characteristics of several products and can affect inventory levels. For example, the Clean Air Act Amendments of 1990 and the low-sulfur diesel regulations of 1993 have required different fuel specifications in different areas, depending on the level of air quality. In addition, some areas have opted to require specifications not mandated by the Clean Air Act[5] The result has been a requirement for a specific grade of distillate for highway use and a proliferation of gasoline formulations sold in specific geographic regions.

Geographically unique product specifications have to a certain degree de-commoditized gasoline in some parts of the United States. This can limit the ability to redirect supply when inventory becomes scarce. Product becomes more difficult to divert from one market to another to meet immediate requirements since it may need to be specifically manufactured, stored, and transported.

Conventional wisdom and the industry expectation was that the increase in product formulations would result in an increase in product tankage and, therefore, an increase in required operating inventory. However, due to the low profitability of the downstream business, companies focused on low investment options to satisfy these new requirements. In addition to investing in new facilities, the industry aggressively changed its operating practices, with the objective of meeting regulatory requirements while maintaining or even reducing transportation, distribution, and inventory costs.

The petroleum industry changed and improved a number of operating practices to meet the new clean-fuel market requirements. Activities included:

- Implementing efficiency improvements such as information technology
- Adding in-line blending to terminals to eliminate the need to transport and store midgrade gasoline
- Increasing use of product exchanges so that each company carries fewer grades but still can supply a full range of products, maximizing the use of existing tankage
- Offering fewer grade choices in certain markets (e.g., only low-sulfur instead of low- and high-sulfur diesel)
- Sharing terminal facilities to lower unit costs and close uneconomic facilities.

The required seasonal changes in gasoline specifications further encouraged inventory reductions. Regulations stipulate substantial differences between winter and summer gasoline grades, and impose severe penalties for using a grade that is less stringent than required. Summer Reid Vapor Pressure (RVP) specifications are lower than winter, so the transition from winter to summer requires that any leftover winter product be stored until the following winter or be reprocessed, both very expensive options. Furthermore, since the summer lower-RVP gasoline is more expensive to make than the winter grade, refiners are reluctant to begin manufacturing summer gasoline too early or overproduce summer gasoline at season's end because these costs would not be recoverable in the market. The net effect is for suppliers to reduce finished gasoline inventory to facilitate meeting the seasonal quality transition requirements.

Acquisitions, Mergers, and Joint Ventures

Another factor contributing to lower inventories has been the restructuring of the U.S. oil industry. Companies always evaluate strategic acquisitions, alliances, mergers, and joint ventures, but in the last five to six years the industry has experienced consolidations of assets throughout all areas of the petroleum business. Financial performance is improved by leveraging the synergies of the companies while reducing operating costs in areas of duplication. Redundant costs are reduced or eliminated, and assets are realigned to leverage utilization efficiencies to better serve the needs of the former

[5] Energy Information Administration, *The Energy Information Administration's Assessment of Reformulated Gasoline*, Volume 1, SR/OOG/94-02/1, October 1994, pp. 33-39.

two entities. These financial benefits are anticipated to be superior to what the companies could have realized separately. For example, if the companies own and operate two distribution terminals in the same marketing region, one terminal could be leased or sold. This revenue would then be available to invest in other areas of the business. If the facility could not be leased or sold, the tanks could be evaluated as potential storage for alternative products, or as discretionary storage, or they could be taken out of service altogether.

Rationalization and consolidation is thought to have reduced the amount of tankage and, therefore, the amount of inventory in the distribution system, despite growing refinery runs and product demand. An example of how rationalization results in inventory decline is given by Ultramar Diamond Shamrock (UDS) CEO Roger Hemminghaus, who indicated that the UDS-Total merger would result in a 2 million barrel reduction in overlapping crude oil and product inventories.[6]

Further examples of industry rationalization over the last couple of years include the joint ventures of Valero and Phibro, Marathon and Ashland Petroleum's refining and marketing operations in the Midwest, and between the western assets of Shell Oil and Texaco to form Equilon. Further rationalization can be anticipated from the merger of Shell/Texaco/SRI downstream assets and from the BP/Amoco consolidation.

Changes in Refining

The significant decline in petroleum demand in the early 1980s, coupled with petroleum price and allocation decontrol in 1981, brought about the closure of many small refineries and bulk terminals. Between 1981 and 1986, 108 U.S. refineries were closed (Figure 1-12), one-third of the total.

A variety of factors have affected refinery capacity and operation. In spite of the continued shutdown of small refineries and the downsizing of several large refineries, U.S. atmospheric distillation capacity is now 15.6 million barrels per day, just over where it was in 1987. Refinery expansion and contraction does not result in significant inventory changes unless the change is major because most refinery inventories are held to allow optimization of the refinery complex. Within a refinery, tankage may be shifted from one product to another to meet demand shifts or seasonal storage needs. The continuous drive to lower costs encourages tank optimization.

Changes in Pipelines

Since 1986, overall miles of installed pipeline have not changed significantly. Pipelines have adjusted to accommodate the changing supply and demand patterns with pipeline reversals, conversions between crude oil and product pipelines, technology improvements, and the upgrading of pumping stations and other equipment that enhance throughput. Use of information technology has automated, streamlined, and facilitated the comprehensive inventory management of pipeline systems and the terminals within them. As a result, pipeline stocks have seen little change since 1987, although more product volume is being transported.

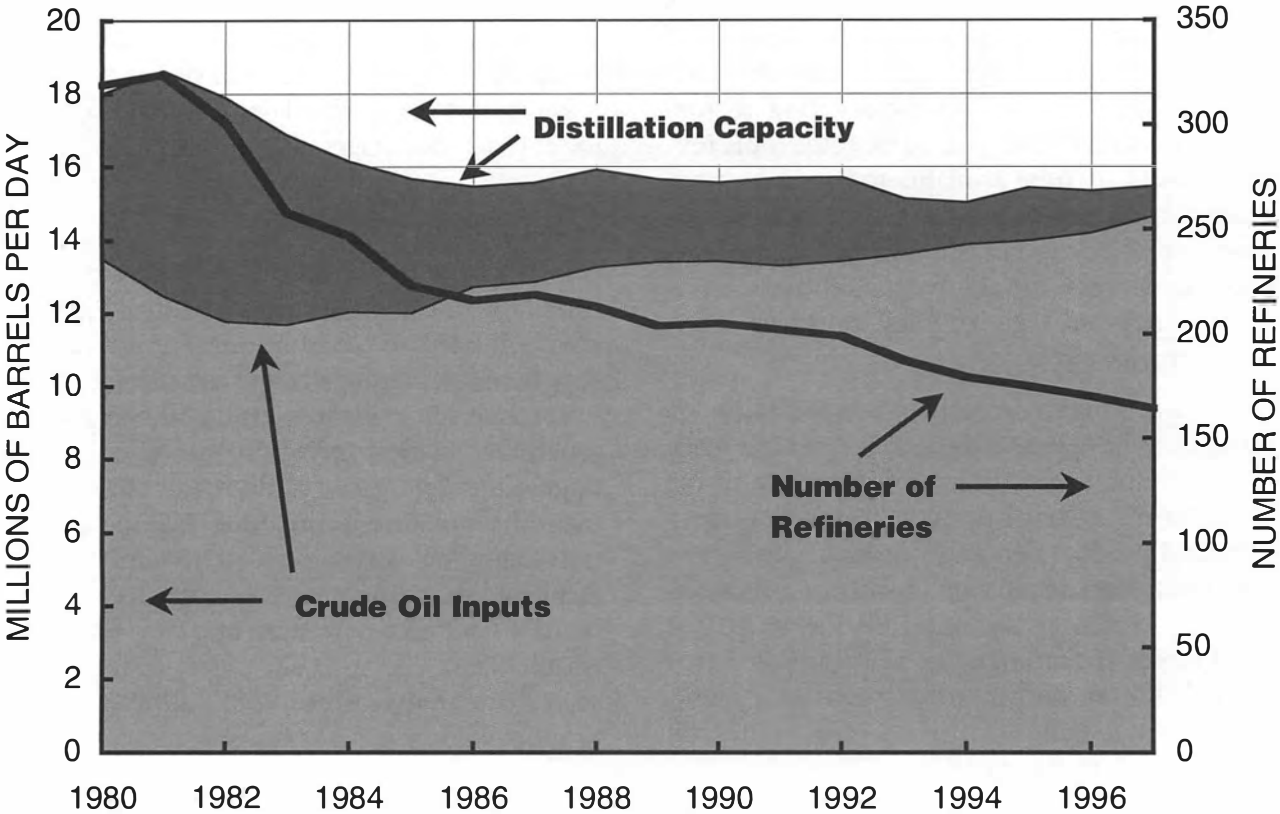
However, there are a number of new projects in various stages of completion that should add to pipeline product inventories in the near future. Among these are pipeline conversions on the Texas, Longhorn, and Seaway-Standish pipelines, all of which have recently been converted from crude oil to product service. Expected addition to pipeline product inventories as a result of these conversions is approximately 3 million barrels in PADD III and 0.4 million barrels in PADD II. However, this increase may be offset by inventory reductions elsewhere in the product supply system.

Changes in Bulk Terminals

Two areas of change in bulk terminals that have contributed to inventory trends have been the reductions and consolidations of the number of operating terminals and improvements in inventory management practices. The rationalization of the bulk terminal system appears to have been more extensive than that of the refining system. While this cannot be verified directly, the fact that terminal inventories declined while refinery inventories did not,

[6]*Octane Week*, Hart/IRI Fuels Information Services, Arlington, VA, April 21, 1997, p. 8.

Figure 1-12. U.S. Refining Trends.



Source of Data: Energy Information Administration.

provides indirect evidence. EIA bulk terminal survey respondent reductions also provide an indication of the consolidation and shutdown activity. Bulk terminal survey respondents went from 703 in 1986 to 546 in 1998, a 22 percent reduction, with over 80 percent of the decline coming from PADDs I and II.

Bulk terminal operations have achieved operational efficiency improvements through several approaches. Company exchanges are not new, but their increased use has allowed each company to carry fewer product grades at each location while still supplying the full range of products to their customers. Companies also increased the sharing of underutilized storage facilities to increase efficiency, lower overall operating costs, and remove unneeded tankage from service. This consolidation of storage not only optimizes the storage facilities, it also increases supply reliability and smoothes ratability as a larger share of total demand for an area is managed from the same facility. In the same vein, many companies have opted to use third-party terminal providers, finding that less expensive than maintaining and operating their own. The third-party terminal operator has the ability to optimize tankage by managing several companies' inventories.

Another significant change in inventory management has been the increased use of in-line blending spurred by the proliferation of products from the Clean Air Act Amendments of 1990. Many terminals now have in-line blending systems that allow the production of multiple products. This has also facilitated the growth of company exchanges and the sharing of tankage. In-line blending also allows oxygenate blending to be performed at the terminal and has eliminated the need to blend, transport, and store midgrade gasoline upstream of the bulk terminal truck rack. Increased blending does carry with it the risk that a supply outage of a base product will generate a simultaneous outage of its blended derivative products.

Chapter Two

U.S. Oil Inventory Trends and Lower Operating Inventories

U.S. PETROLEUM INVENTORY TRENDS

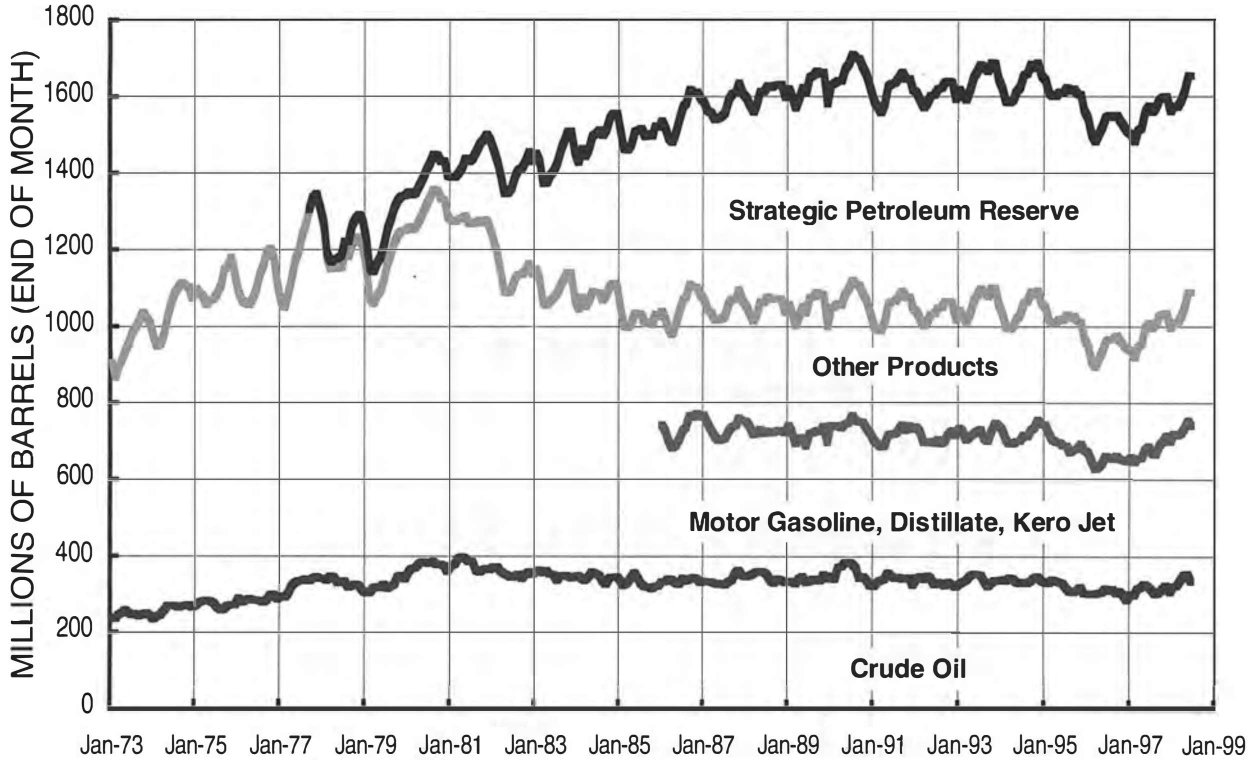
U.S. petroleum inventories respond to both market and infrastructure changes in the supply system. This chapter investigates the behavior of gasoline, distillate, and kerosene jet fuel inventories since 1986 and defines a lower operating inventory level for these products based on observed data. With the exception of finished gasoline inventory held at terminals, no significant downward trends in the absolute inventory levels were identified. Because the supply of crude oil is fundamental to the ability of the refining system to supply product to markets, the study also investigated and defined a lower operating level for crude oil inventory. Permanent downward trends in crude oil lease stocks and Alaskan crude oil in-transit were identified.

Total Inventories and Days of Supply

Figure 2-1 shows monthly U.S. primary inventories for crude oil, the light products investigated in this study, and other petroleum products in the United States from January 1973 through June 1998. In the 1970s, inventories were on a general upward trend. Following the Iranian crisis in 1979, the significant reductions in demand in the early 1980s, and the decontrol of product prices in 1981, product inventories declined fairly rapidly to a lower level in response to the changed market conditions. Since the mid-1980s, total product inventories have been relatively flat, with a significant drop during the 1995–96 period and the subsequent rebound. While overall product inventories show little change, there has been a slow downward trend in major light petroleum product inventories. In addition, beginning in the late 1970s, the United States began to fill the Strategic Petroleum Reserve.

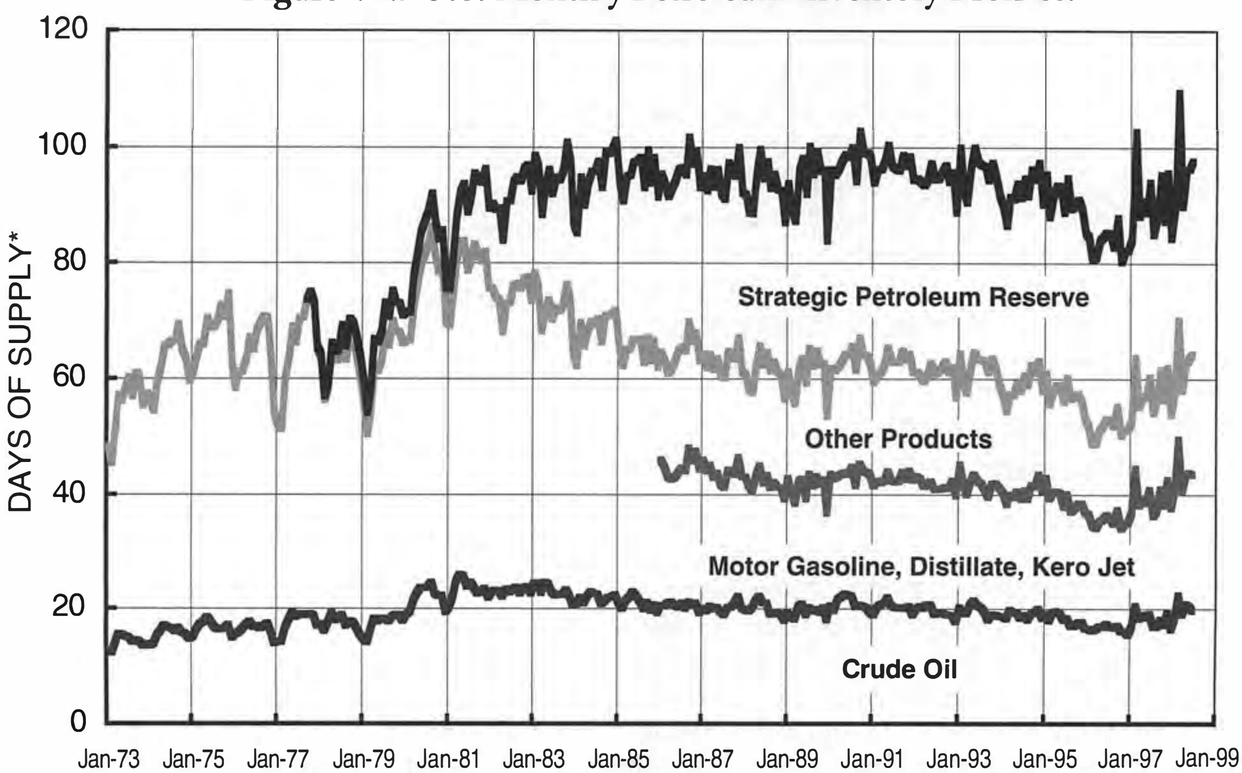
Another way of looking at overall inventories is in days of supply, the inventory level (barrels) divided by demand (barrels/day). Figure 2-2 shows the inventory data from Figure 2-1 divided by the total daily average oil demand for the month. On a days-of-supply basis, there has been a slow, steady decline in inventories, particularly for products. It is generally known within the petroleum industry that most reported primary inventory is not available for consumption under "normal" operation. This inventory, needed to keep the petroleum supply system operating efficiently, has traditionally been defined as minimum operating inventory (MOI). The MOI includes inventories such as pipeline fill and tank bottoms, as well as estimates of the necessary minimum working inventory to keep the petroleum supply system operational. By definition, MOI excludes both seasonal inventories and inventories held as a financial opportunity.

Figure 2-1. U.S. Monthly Petroleum Inventory Profiles.



Source of Data: Energy Information Administration.

Figure 2-2. U.S. Monthly Petroleum Inventory Profiles.



****Days of Supply calculated by dividing each inventory category by total petroleum demand.***

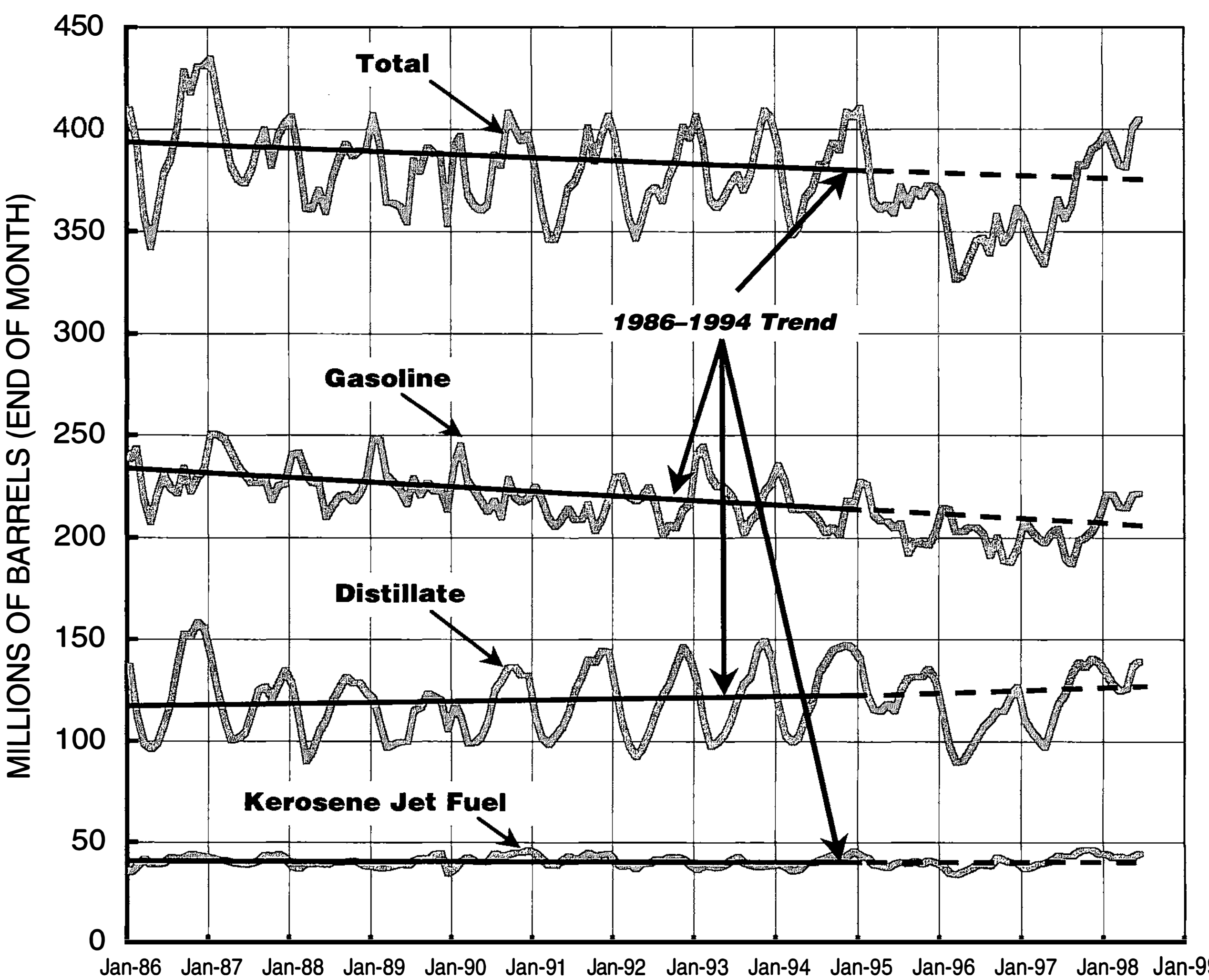
Source of Data: Energy Information Administration.

MOIs are relatively insensitive to throughput, and hence a gradual decline in days of supply is expected as the industry achieves higher throughput rates without adding significant new infrastructure. While this reduction reflects improvements in efficiency, it does not reflect a lower level of supply reliability.

Overall Major Light Petroleum Product Inventory Trends and Inventory Components

Figure 2-3 shows total U.S. gasoline, distillate, and kerosene jet fuel inventories from January 1986 through June 1998 as reported by the EIA. A trend line based on the data from 1986 through 1994 indicates a slow downward trend in total inventory at the rate of about 1.4 million barrels per year. The monthly data illustrate the significant inventory cycle that occurred from late 1995 through 1998, where inventories are believed to have been near the minimum and maximum of their operating range. Figure 2-3 also shows the data split into individual series for gasoline, distillate, and kerosene jet fuel. The individual product inventory trends indicate that the overall major light petroleum product downward trend is the result of a downward trend in gasoline inventories (2.2 million barrels per year) partially offset by a small upward trend in distillate inventories (0.8 million barrels per year). Kerosene jet fuel inventory shows no significant trend over the period. While the distillate trend results from a combination of small trends in various reporting segments and is not significant, the gasoline trend is dominated by the reduction of finished gasoline inventory in terminals.

Figure 2-3. U.S. Major Light Petroleum Product Inventory Trends.



Source of Data: Energy Information Administration.

Industry observers generally follow inventories as a single number for any particular product in some specified geographic area. In reality, the inventory consists of data from many reporters from various industry segments and, in the case of gasoline, distillate, and crude oil, multiple components. Very specific market forces can influence each of these segments. Hence, overall inventory data can sometimes hide important underlying trends.

In general, inventory data collected by the EIA consist of pipeline, terminal, and refinery inventories. The basic geographic coverage for inventory data is by Petroleum Administration for Defense District (PADD), with some major product inventory data available by state. In addition to refinery, terminal, and pipeline inventories, crude oil inventory normally includes lease stocks and Alaskan oil in-transit and may or may not include crude oil held in the Strategic Petroleum Reserve. Analysis of inventories in aggregate can result in misinterpretation of statistical changes due to changed reporting and changes that are not relevant to supply adequacy (e.g., Alaskan crude oil in-transit).

Gasoline inventory is normally reported as the sum of finished gasoline and gasoline blending components. Blending components, as currently defined, exclude oxygenates, which have become an integral part of gasoline supply since the 1989 NPC report, *Petroleum Storage & Transportation.* Distillate includes both low-sulfur and high-sulfur grades. Since the U.S. petroleum distribution system tends to consist of two major groupings, east and west of the Rocky Mountains, this study analyzed inventory data based on the sum of PADDs I through IV and PADD V.

Light Product Terminal Inventories

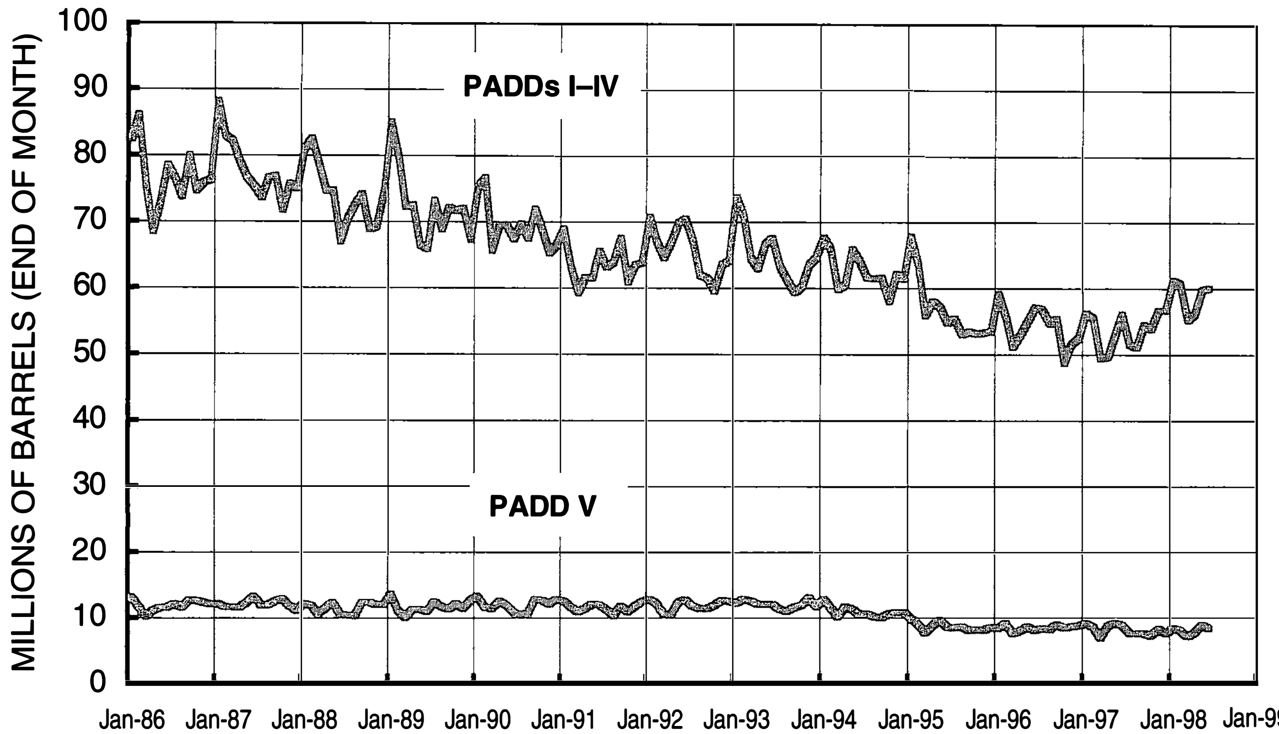
Terminal inventories are reported to the EIA on Form EIA-811 "Monthly Bulk Terminal Report." Every bulk terminal in the United States and its possessions is required to report. A bulk terminal is a facility that is primarily used for storage and/or marketing of petroleum products, that has a storage capacity of 50,000 barrels or greater, or that receives petroleum products by barge, tanker, or pipeline. However, facilities that would fit the terminal definition but produce finished products by blending ("blenders") are reported in the refinery category, not in the terminal category. Bulk terminal facilities associated with product pipelines, as well as inventories held by merchant oxygenate plants, are also collected on the terminal form. In total about 320 respondents, many of whom have more than one terminal, report on this form. While the exact count of the number of terminal facilities is difficult to determine, all data suggest significant reductions in the actual number of operating petroleum terminals in the United States since the mid-1980s.

Terminal inventories are the closest primary inventories to end-users. Beginning in January 1993, a number of facilities were moved from the terminal category to the refinery category as a result of expanded blending operations associated with the oxygenated and reformulated gasoline programs. This change resulted in about 5 million to 10 million barrels of gasoline and small amounts of distillate and kerosene jet fuel inventories moving from the terminal category to the refinery category.

Finished Gasoline

Figure 2-4 shows finished gasoline inventories reported by terminals for PADDs I–IV and PADD V. These inventories have had a persistent downward trend since the mid-1980s—about 2 million to 2.5 million barrels per year in PADDs I–IV and about 0.3 million barrels per year in PADD V. Terminal inventories account for the entire downward trend in overall gasoline inventory. This trend did not seem to be significantly influenced by the step change in reporting that occurred on January 1, 1993. The distribution system for gasoline has undergone significant operational changes since the 1989 NPC report, *Petroleum Storage & Transportation.* The logistics system response to these changes, such as the use of fungible regular gasoline and the terminal blending of midgrade gasolines, are no doubt a significant factor in the continued downward trends. However, the reduction in finished gasoline inventory held at terminals began before many of the major changes in the gasoline market, which suggests an underlying pattern consistent with the economic drivers to optimize facility use. While it is impossible to accurately predict

Figure 2-4. Finished Gasoline Inventories at Terminals.



Source of Data: Energy Information Administration.

how inventories will change in the future, continued reductions in terminal nondiscretionary inventories are expected over the next several years as a result of continued industry consolidation.

Gasoline Blendstocks and Oxygenates

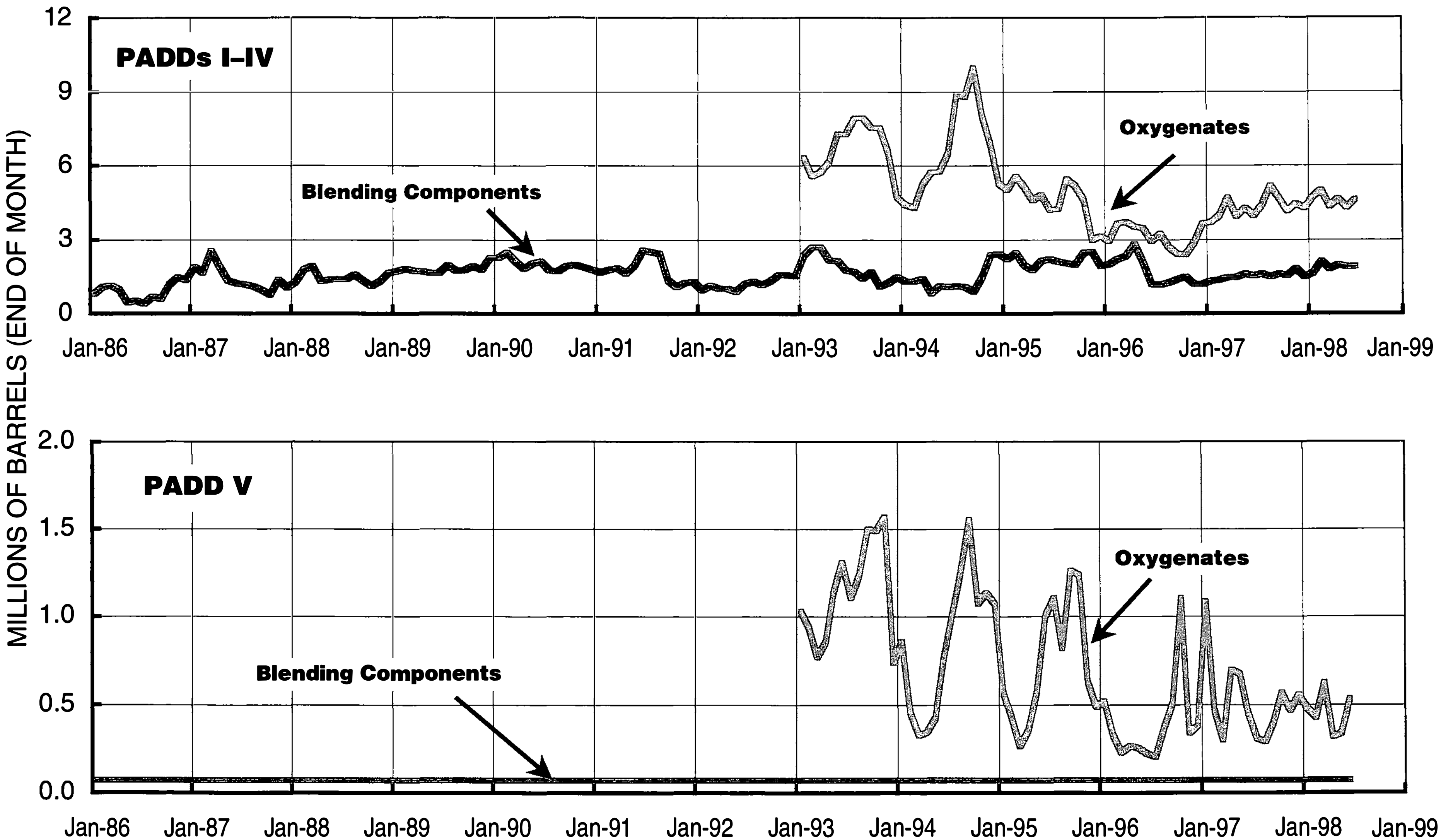
Figure 2-5 shows the gasoline blendstocks and oxygenates held in terminals. While important in some geographic locations, in general, these inventories are small relative to finished gasoline inventory. As mentioned previously, these data do not include a number of terminal facilities that were blending finished gasoline and were reclassified as refineries after 1992. Before the year-round oxygenate requirements for California and for reformulated gasoline, oxygenate inventories grew seasonally to provide the oxygenate required for winter gasoline used in carbon monoxide nonattainment areas. Oxygenate inventory now seems to have leveled out, and future trends will likely be dependent on regulatory requirements for oxygenates in gasoline. Blending components in terminals remain small and do not show any significant trend.

Distillate and Kerosene Jet Fuel

Figures 2-6 and 2-7 show trends in terminal inventories of distillate and kerosene jet fuel for PADDs I–IV and PADD V, respectively. In contrast to gasoline, these products do not exhibit any significant long-term downward trend. As shown on Figure 2-6, PADD I–IV terminal distillate inventory peaked at about 70 million barrels in the fall of each year from 1990 through 1994. In 1995 through 1997, inventory peaked in the 50 million to 55 million barrel range. At the end of June 1998, PADD I–IV terminal distillate inventory was 58 million barrels, the highest monthly closing level since January 1995. Terminal kerosene jet fuel inventory does not show any significant trend in PADDs I–IV.

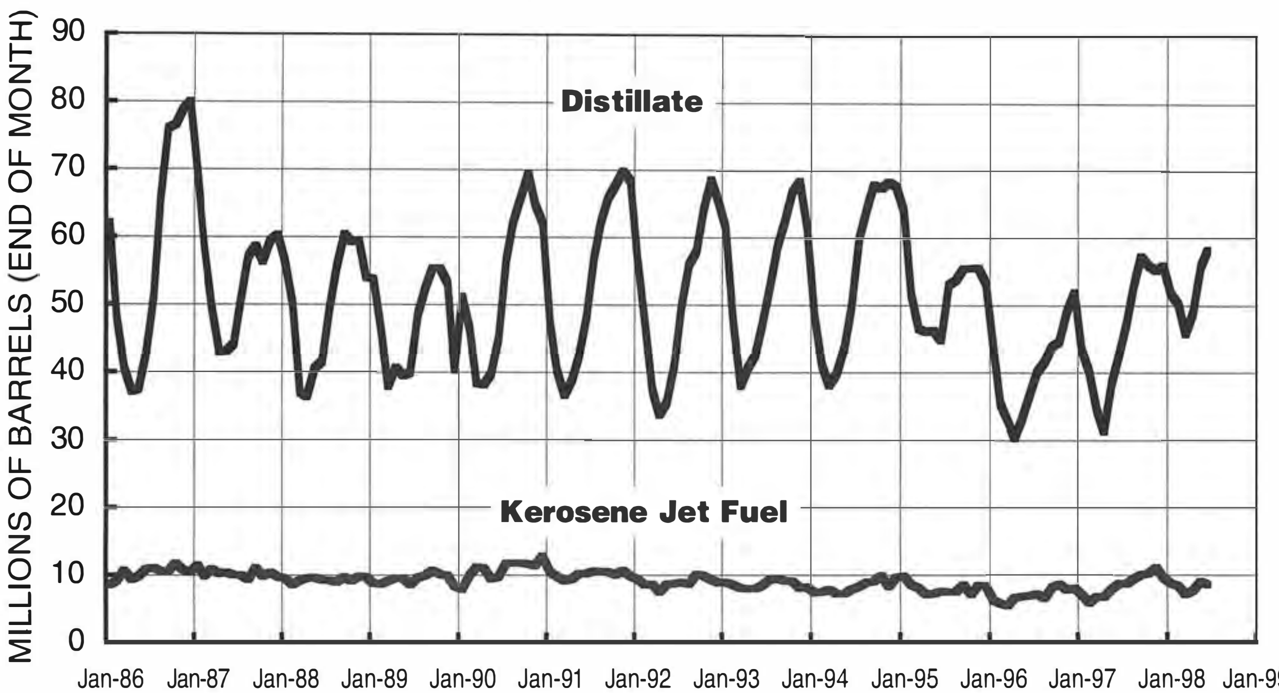
PADD V terminal inventories are about 10 percent of the PADD I–IV distillate inventory and about 20 percent of the PADD I–IV kerosene jet fuel inventory, as shown on Figure 2-7. Some small upward trend in kerosene

Figure 2-5. Gasoline Blending Components and Oxygenate Inventories at Terminals.



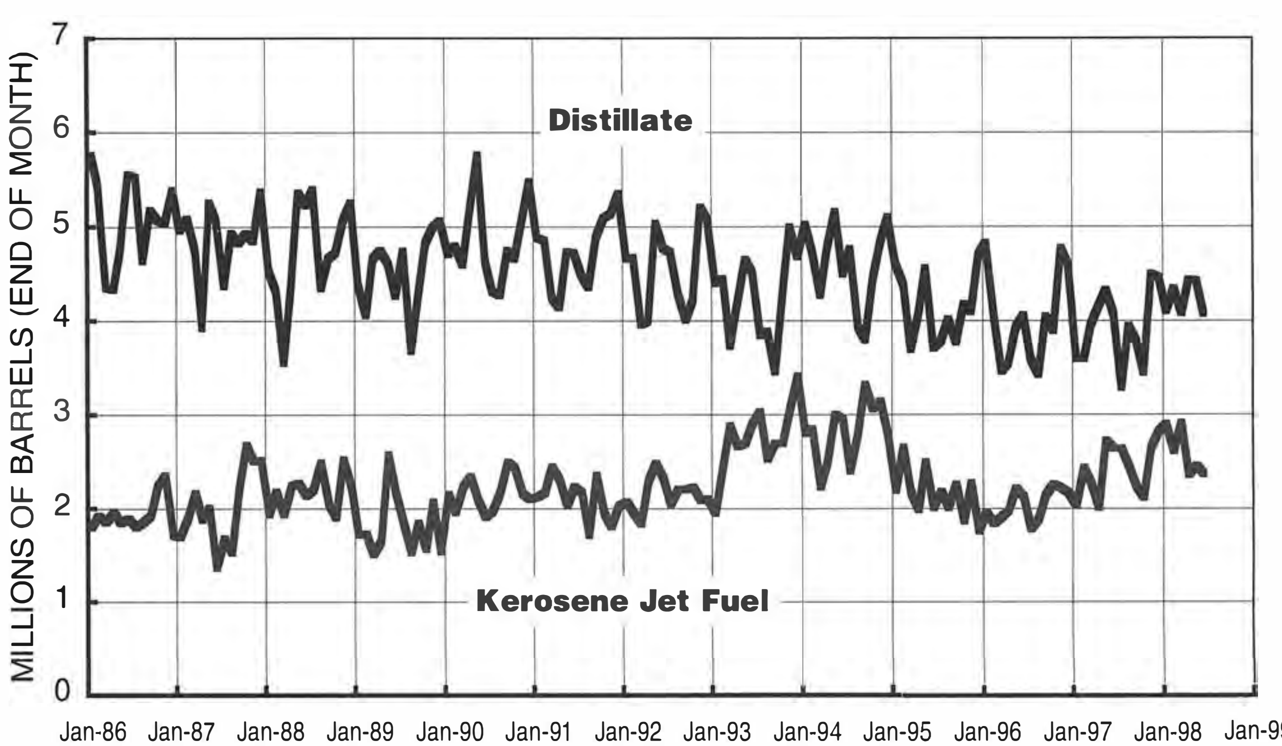
Source of Data: Energy Information Administration.

Figure 2-6. PADDs I–IV Distillate and Kerosene Jet Fuel Inventories at Terminals.



Source of Data: Energy Information Administration.

Figure 2-7. PADD V Distillate and Kerosene Jet Fuel Inventories at Terminals.



Source of Data: Energy Information Administration.

jet fuel inventory and a small downward trend in distillate inventory can be observed. These trends are not judged to be significant and are likely the normal economic system response to market changes such as the conversion of the military to a kerosene-based jet fuel and the introduction of CARB and EPA quality diesel into the market.

PADD I–IV Refinery and Pipeline Inventories

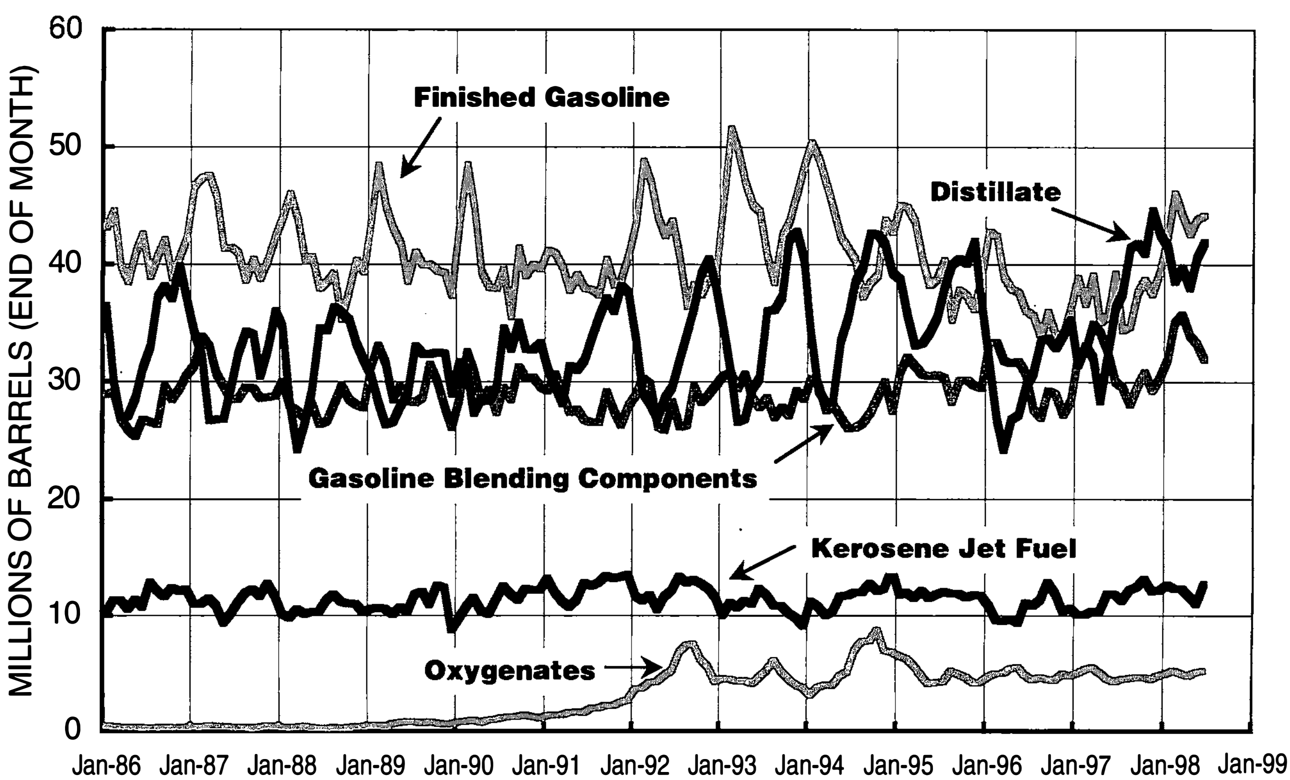
Operators of all operating and idle petroleum refineries and blending plants report to the EIA as refiners on the EIA-810 "Monthly Refinery Report." There are about 260 respondents, with each facility reporting independently. Pipeline data are reported on the EIA-812 "Monthly Product Pipeline Report," which covers all product pipeline companies (including interstate, intrastate, and intracompany pipelines). There are about 80 pipeline reporters.

Figures 2-8 and 2-9 show PADD I–IV refinery and pipeline product inventories for finished gasoline, gasoline blending components, oxygenates, distillate, and kerosene jet fuel. Other than perhaps a small decrease in finished gasoline inventory, no reductions can be observed relative to the typical values in the late 1980s. If blending components and oxygenates are added to finished gasoline inventory, the overall level of gasoline and its potential blending components in pipelines and refineries may, in fact, be slightly increasing.

PADD V Refinery and Pipeline Inventories

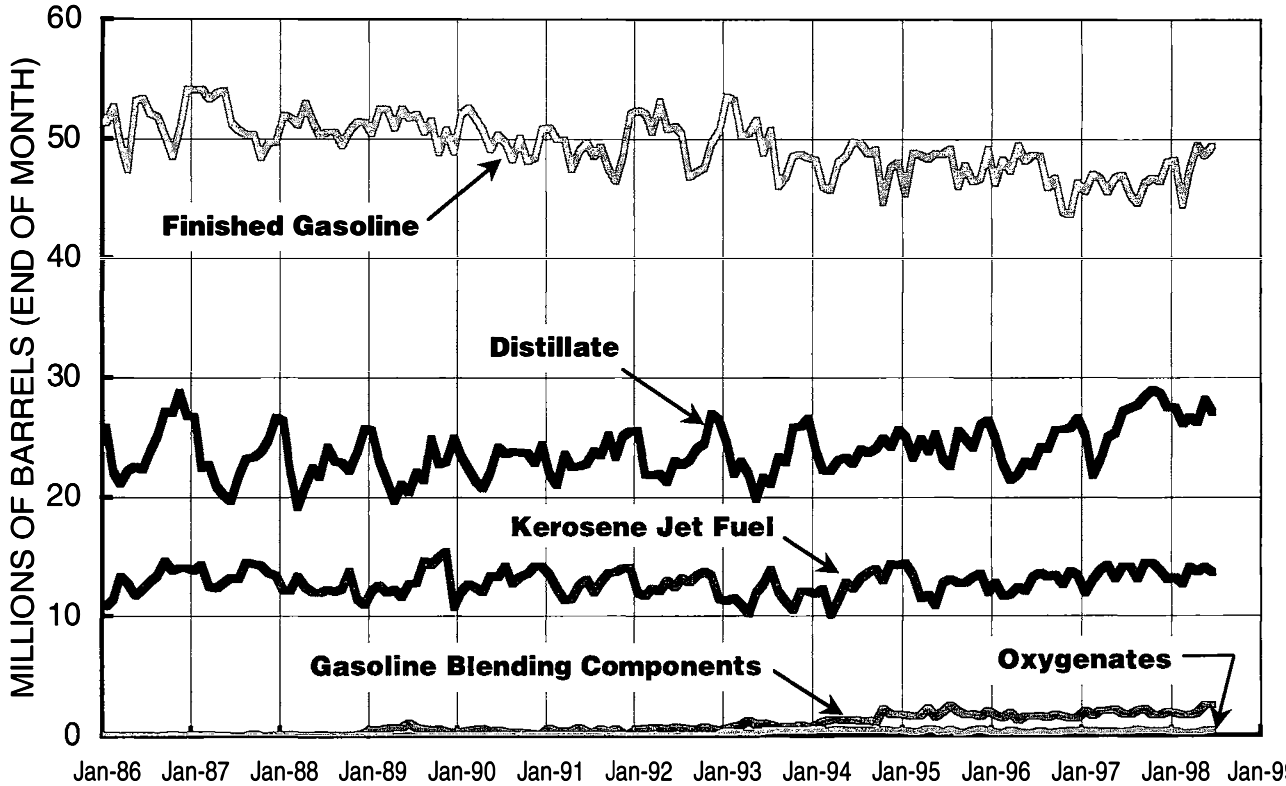
Figures 2-10 and 2-11 plot PADD V refinery and pipeline product inventories. Most of these inventories seem to be on slow upward trends. These trends illustrate that inventories can and will increase as necessary to meet market requirements. The increasing PADD V inventories probably reflect increasing demand, less supply flexibility because of relative isolation from other supply sources, and the specialized gasoline and diesel formulations sold in the California market.

Figure 2-8. PADDs I–IV Refinery Product Inventories.



Source of Data: Energy Information Administration.

Figure 2-9. PADDs I–IV Pipeline Product Inventories.



Source of Data: Energy Information Administration.

PADD I–IV Crude Oil Inventories

The primary focus of this study is major light petroleum products in the United States. However, given the critical importance of crude oil as a feedstock to the refining industry, crude oil inventory trends were also investigated.

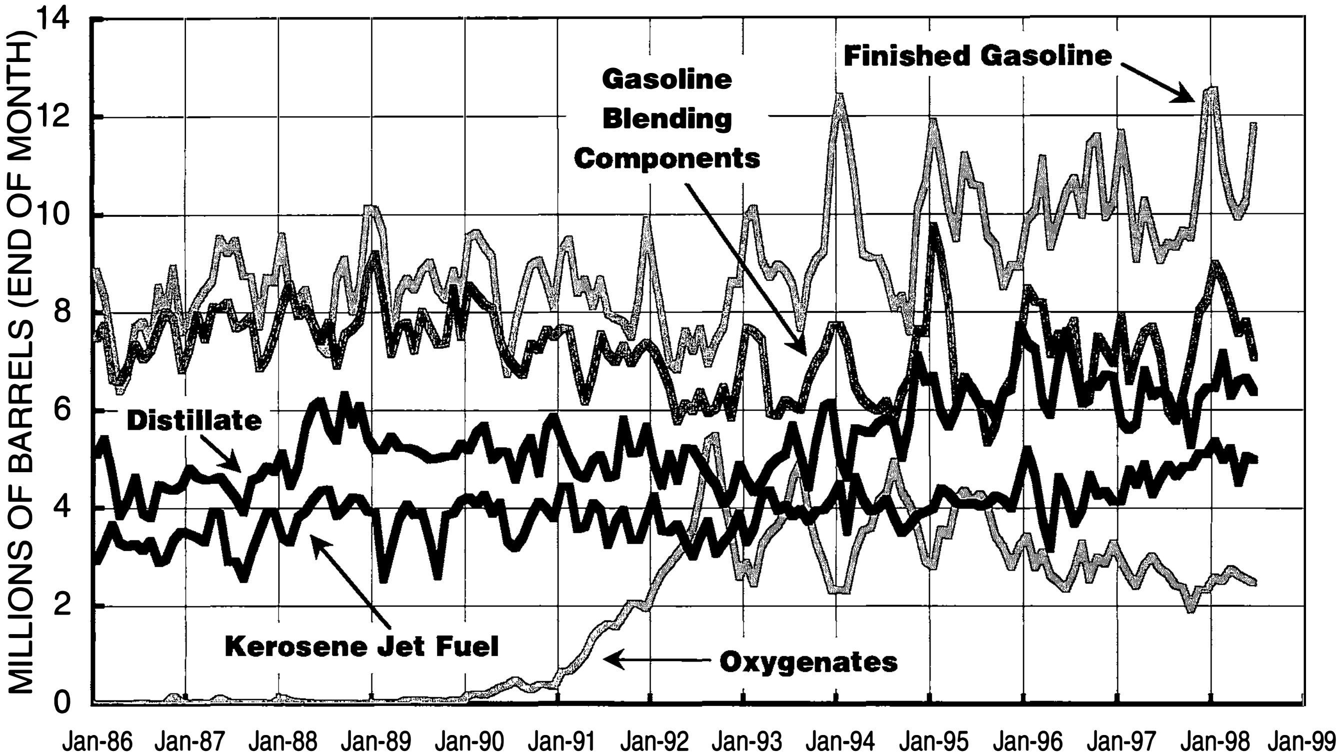
Crude Oil on Leases

Figure 2-12 shows the profile of PADD I–IV crude oil inventory split among leases, refineries, and pipelines and terminals. Lease stocks, most of which are in PADDs I–IV, are crude oil inventory held on production leases awaiting transportation to a refinery for processing. Of the approximately 15 million barrels of lease stocks currently reported by EIA, only about 5 million barrels represent actual data, with 10.63 million barrels imputed by the EIA for nonreporting entities. Reported inventory has been in steady decline since 1986 and is currently about 5 million barrels lower than the reported inventory in 1986. The most likely cause of the decline is the reduction in onshore U.S. crude oil production.

Crude Oil at Refineries

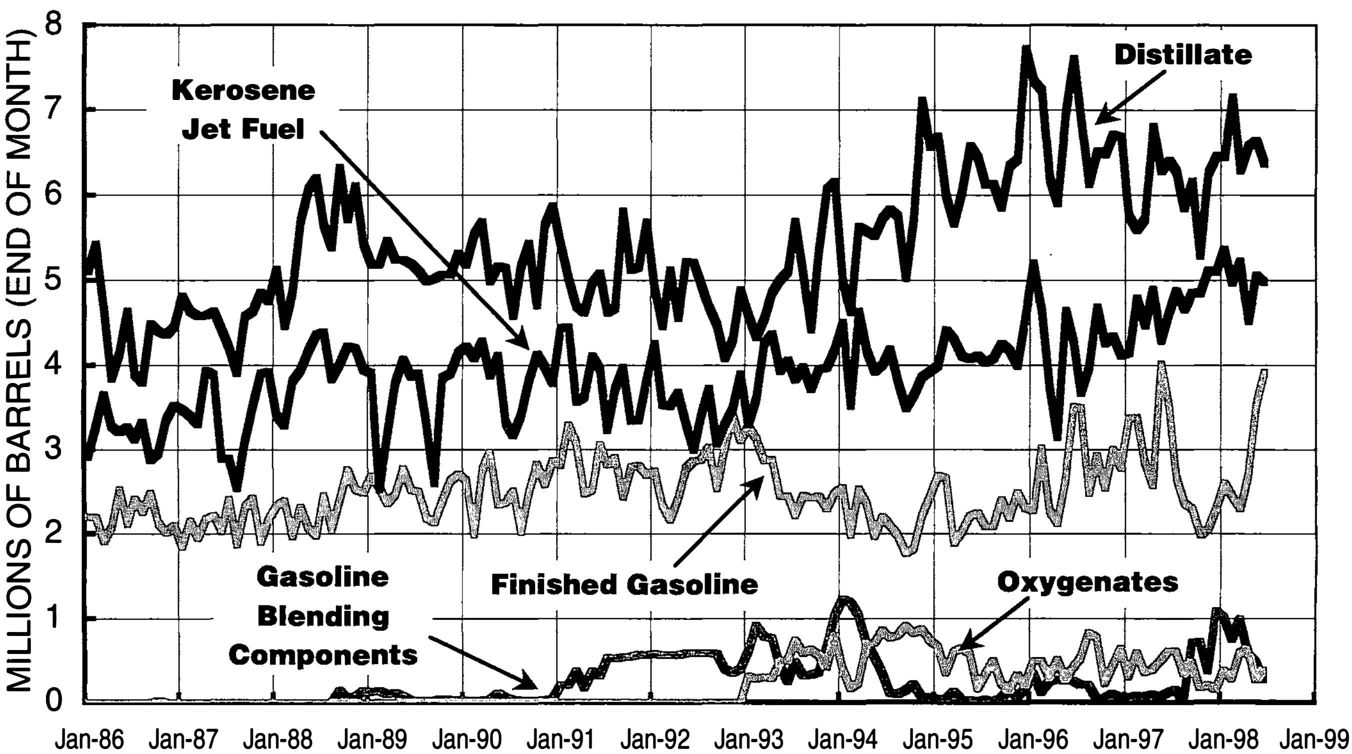
The lowest observed refinery crude oil inventory level in PADDs I–IV since January 1986 was 64.1 million barrels in December 1995. This low observation is only 1.5 million barrels, or about 2 percent below the level reported by refineries for December 1986. In PADDs I–IV, six of the ten lowest crude oil inventory observations at refineries occurred in December, two occurred in January, and two occurred in February of the same years as the January reported lows. This phenomenon may be explained by year-end inventory management strategies. Low ending December inventory reflects this action with low January and February levels resulting from slow inventory builds from December. In addition, the relatively flat profile of crude oil inventory at refineries suggests that nearly all refinery inventory is

Figure 2-10. PADD V Refinery Product Inventories.



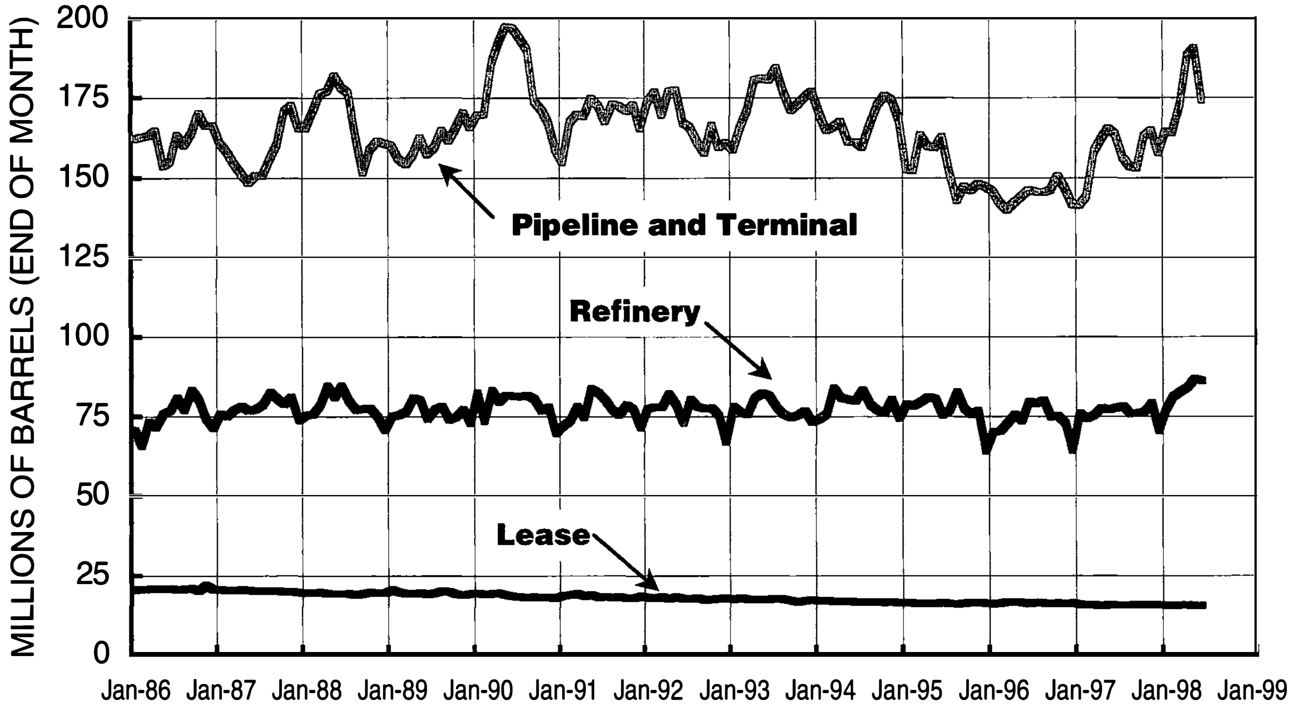
Source of Data: Energy Information Administration

Figure 2-11. PADD V Pipeline Product Inventories.



Source of Data: Energy Information Administration.

Figure 2-12. PADDs I–IV Crude Oil Inventories.



Source of Data: Energy Information Administration.

held for operational reasons and there is a relatively small response to market conditions.

Crude Oil in Pipelines and Terminals

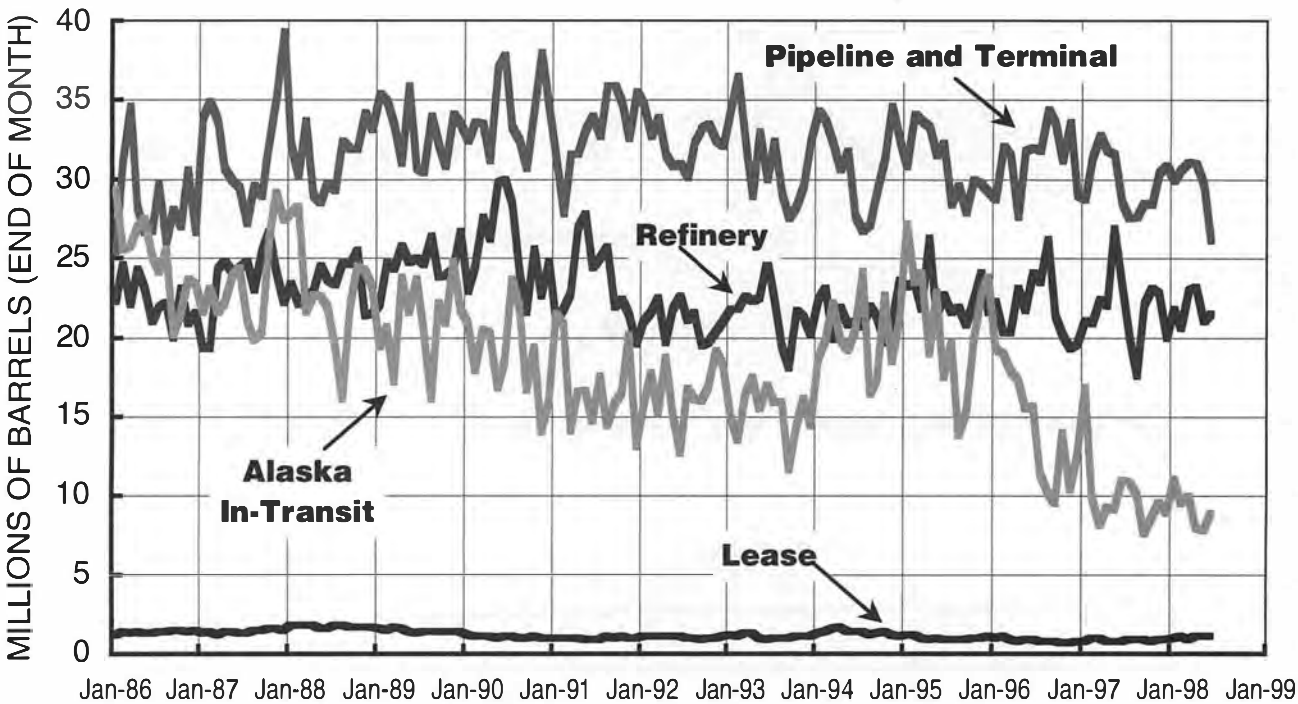
Crude oil pipeline and terminal inventory is extracted from data reported on form EIA-813 "Monthly Crude Oil Report." This report gathers data from all companies that carry or store 1,000 barrels or more of crude oil. Included in this category are gathering and trunk pipeline operators, crude oil producers, terminal operators, storers of crude oil (except refineries), and companies transporting Alaskan crude oil by water to a U.S. destination. About 175 companies respond on this form. Pipeline and terminal inventories are published in aggregate and, as shown on Figure 2-12, can vary significantly in PADDs I–IV. This inventory reached its lowest level in March 1996, at 139.8 million barrels, following a clear downward trend since the second quarter of 1993. Since the low in 1996, this inventory has recovered sharply and approached all-time highs in early 1998. Pipeline inventory is more sensitive to infrastructure changes than to market conditions. However, terminal inventory is very responsive to the market and is no doubt the major cause of overall crude oil inventory movements.

PADD V Crude Oil Inventories

Alaskan Crude Oil In-Transit

Figure 2-13 plots the reported crude oil inventories for PADD V. In addition to refinery, lease, and pipeline and terminal inventories, PADD V data include crude oil in-transit from Alaska to domestic refineries. Alaskan crude oil is only a small portion of the crude oil on the water destined for the United States and, as such, does not provide meaningful information on potential supply vulnerability. In-transit inventory currently averages 8 million to 10 million barrels versus the 20 million to 25 million barrels typical in the mid-1980s. The significant drop results from the decline in Alaskan crude oil production, from its peak of over 2 million barrels per day in 1988 to around 1.2 million barrels per day in 1997, and the lifting of the federal ban on the export of Alaskan crude oil in 1996. Alaskan crude oil in-transit inventory will likely continue to decline unless Alaskan crude oil production increases.

Figure 2-13. PADD V Crude Oil Inventories.



Source of Data: Energy Information Administration.

Other PADD V Crude Oil Inventories

Other crude oil inventory data for PADD V show trends similar to those for PADDs I–IV although the data appear to be more volatile. This may be the result of similar variations in the absolute inventory from logistical operations and infrastructure changes spread over a much smaller base. For example, in 1989, the All American Pipeline became operational. Approximately 800 miles of this 30-inch line lie in PADD V, which added at least 3.7 million barrels, or over 10 percent, to the pipeline and terminal data for PADD V. These types of changes can overwhelm or disguise underlying trends, particularly in PADD V.

MINIMUM OPERATING INVENTORIES

MOI Concept and Tie to Prior Studies

As mentioned previously, it is commonly recognized that a significant part of reported petroleum inventories are operational in nature and not readily available to meet consumer demand. In concept, if MOI could be defined, then inventories available to the market and their potential implications could be more easily addressed. Since the early 1970s, the NPC has defined the MOI for crude oil and major petroleum products several times, with the most recent analysis published in 1989. Traditionally, these studies have included a survey that was used along with other inputs to develop a consensus MOI.

Figure 2-14 shows the historical inventory profile for gasoline, along with the MOI as estimated in the 1974, 1979, 1984, and 1989 NPC inventory studies. Reported total gasoline inventory includes both finished gasoline and gasoline blending components as reported to the EIA. The estimated MOIs for gasoline have been remarkably stable over a very long period, and observed data have tended to confirm these estimates. However, observed data fell below the 1989 NPC *Petroleum Storage & Transportation* study MOI for about 20 percent of the time since 1990, with the first incident occurring in April 1991. The consistent pattern of gasoline inventory level below the MOI was the primary reason that EIA abandoned tracking current inventory against the previously defined MOI.

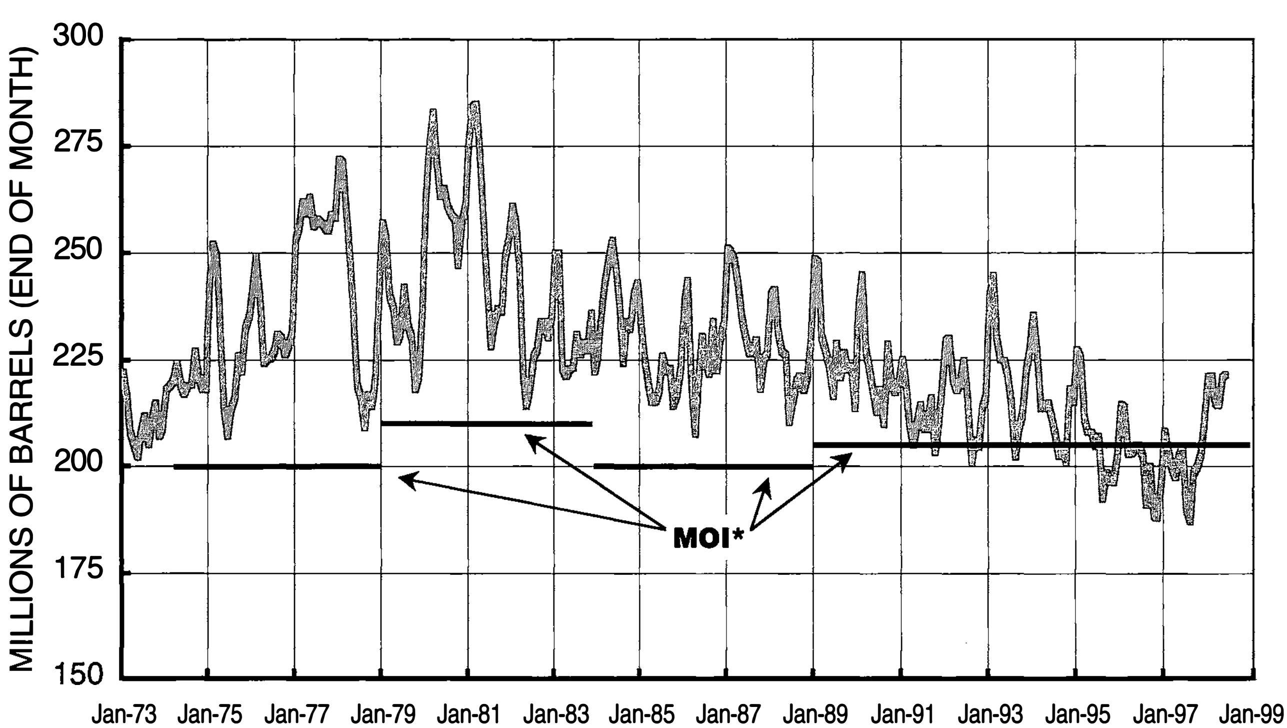
Since the 1989 NPC report, *Petroleum Storage & Transportation*, the gasoline market has undergone significant change. In particular, oxygenates such as ethanol and MTBE have become an important part of the gasoline supply system as a result of the mandated oxygen content of reformulated and oxygenated gasoline. Historically, these nontraditional blending components have not been included in reported gasoline inventory or in assessments of gasoline inventory adequacy. Figure 2-15 repeats the gasoline inventory data shown on Figure 2-14 and from 1990 forward adds the oxygenate inventory band to the top of the reported gasoline inventory. If oxygenates had been included in the inventory data as shown by the top line in Figure 2-15, gasoline inventory would have fallen below the MOI established in 1989 on five occasions, three months in 1996 and two months in 1997, and only by relatively minor amounts. While some of the oxygenate inventory is held in merchant plants, more than half is in refineries and terminals that blend finished gasoline. In the current gasoline supply system, oxygenate inventory is at least as important as other blending components and should be considered when making inventory adequacy assessments.

Figures 2-16 and 2-17 show historical inventory profiles for distillate and commercial crude oil, along with their MOIs from prior studies. The low distillate inventory in 1996 tends to confirm the MOI of the 1989 study. Recent crude oil inventory levels below the 1989 MOI are a result of lower lease stocks and Alaskan in-transit crude oil, as opposed to a change in apparent "operational" inventory requirements.

In addition to the MOIs for gasoline, distillate, and crude oil, an MOI was defined for kerosene jet fuel in the 1983 and 1989 NPC studies and a kerosene/kerosene jet fuel combination in the 1974 and 1979 studies. The 1996 inventory observations suggest no underlying change in the MOI for kerosene jet fuel.

An assessment of the MOI inventory gives some additional perspective on current inventory levels and the inventory flexibility available to help balance markets. However, on occasion,

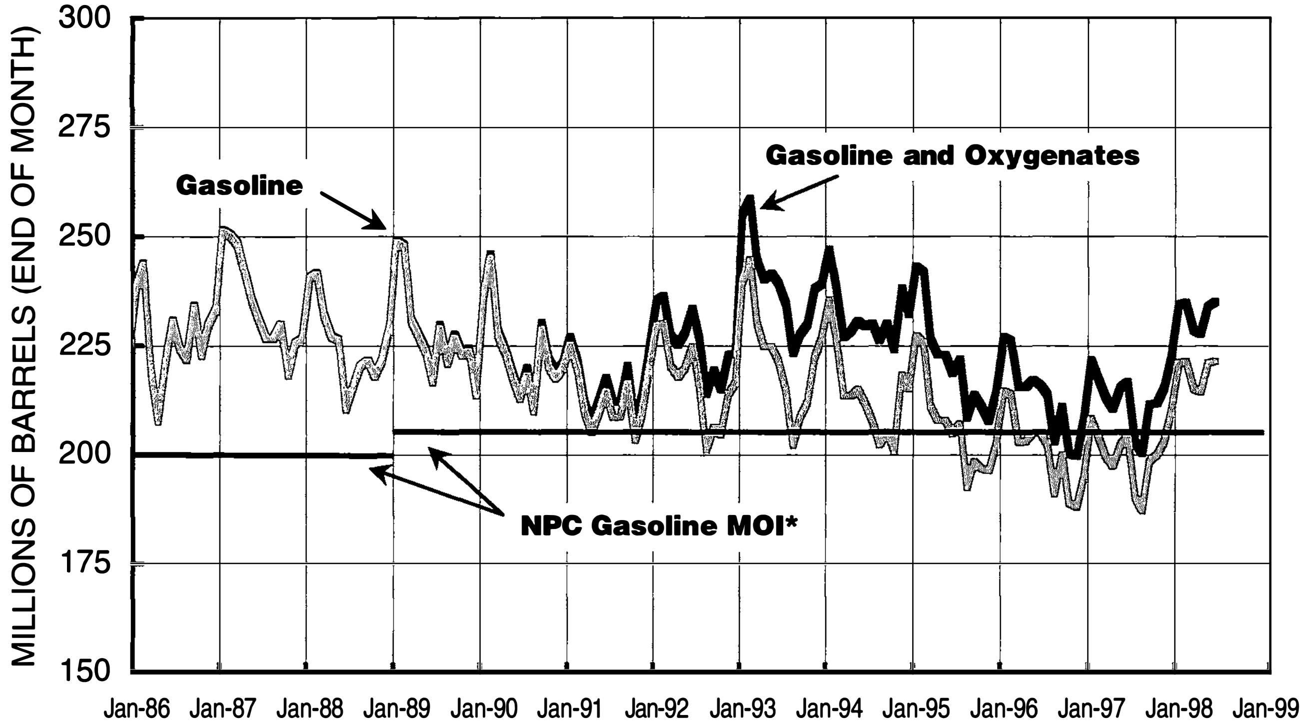
Figure 2-14. U.S. Gasoline Inventory Profile.



****Minimum Operating Inventories estimated in previous NPC studies.***

Source of Data: Energy Information Administration and National Petroleum Council.

Figure 2-15. U.S. Gasoline Inventory Profile Including Oxygenates.



**Minimum Operating Inventories estimated in previous NPC studies.*

Source of Data: Energy Information Administration and National Petroleum Council.

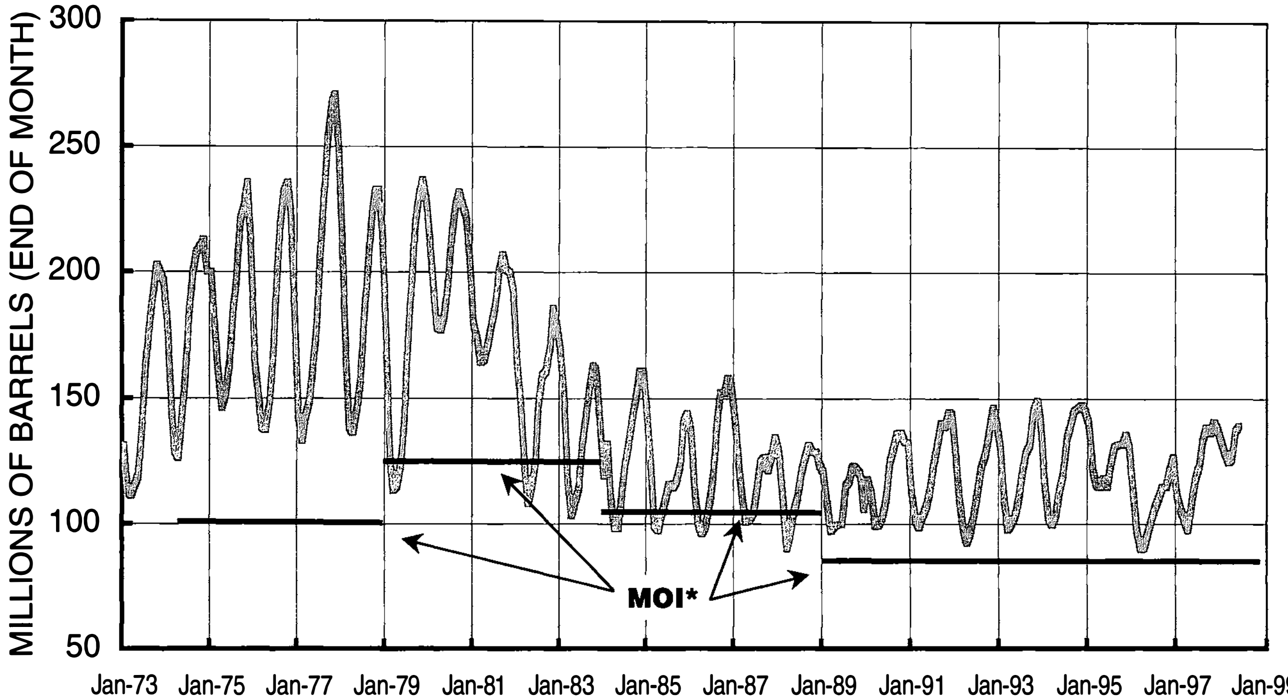
MOIs have been improperly used to suggest that as inventories approached this level, the supply system was in danger of imminent failure or a significant upward retail price movement was likely. History indicates that the MOI concept is not useful for anticipating supply problems. Inventories have gone below previously defined MOIs a number of times with no apparent consumer supply disruptions. While in some cases, this can be attributed to a problem with the definition of MOI, non-crude-oil-related supply problems are normally local and short term. The competitive nature of the downstream petroleum business, the flexibility in the refining and distribution system, and free-market pricing creates continuous change within the petroleum supply system both to meet normal demand and to respond to unexpected events. Widespread supply run-outs at the primary supply level have not occurred in the United States since the Arab oil embargo.

While to a certain extent major light petroleum product inventories are related to price and vice versa, the largest components of consumer petroleum product prices are the cost of crude oil and, in the case of gasoline, taxes. Changes in these prices are driven by world and political events and move independently from the level of U.S. product inventories. As will be discussed in Chapter Three, large consumer price increases caused by product prices increasing relative to crude oil are few, short lived, and localized. Inventories play a role, but most price excursions are event driven.

Issues with MOI and EIA Minimum Observed Inventories

There currently are two common public inventory definitions used to track inventories versus a lower operational bound—the MOIs as defined in prior NPC studies and the minimum observed inventories currently used by the EIA.

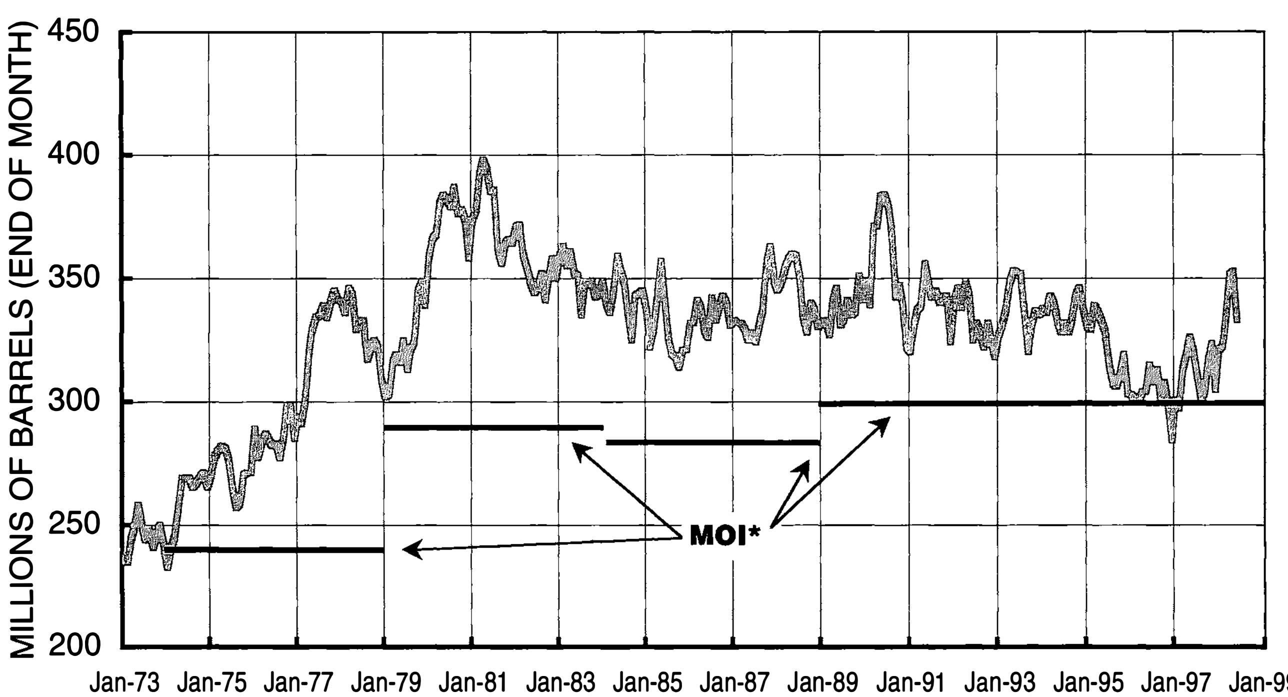
Figure 2-16. U.S. Distillate Inventory Profile.



**Minimum Operating Inventories estimated in previous NPC studies.*

Source of Data: Energy Information Administration and National Petroleum Council.

Figure 2-17. U.S. Crude Oil Inventory Profile.



**Minimum Operating Inventories estimated in previous NPC studies.*

Source of Data: Energy Information Administration and National Petroleum Council.

The MOI is defined as follows in the 1989 NPC report, *Petroleum Storage & Transportation.*

> Minimum operating inventory is defined as the level below which operating problems and shortages would begin to appear in a given distribution system. However, in stress situations, inventories can drop below this level for short periods without significant supply disruptions, but with increased operating costs.

This MOI definition has resulted in a misinterpretation of the minimum operating inventory concept. First, because inventories represent operating costs, the competitive nature of the petroleum supply system drives the industry to the most efficient operation to meet demand. Depending on current markets, geographic demand, costs, logistical requirements, changing regulations, industry changes, and a host of other factors, the lower operational limit of future inventories may be above or below today's best estimate of MOI. MOIs are not static. Second, although the definition of MOI relates to a given distribution system, MOIs are typically developed and applied across a broad geographic range encompassing multiple distribution systems. Deliverability issues, when they arise, are generally local. The definition of a broad geographic inventory as an indicator of a potential local supply issue is problematic at best. Finally, the definition implies that MOI is an absolute. Some observers have misinterpreted inventory levels below MOI as a sign of imminent failure of the supply system.

The EIA currently uses minimum observed inventories, which are defined as the lowest inventory observed in the last three years, as a mechanism to relate current inventory to a lower operational level. While straightforward, this methodology can be very misleading. If inventories remain in the upper portion of the operating band for several years, the demonstrated lower operational data are lost. This runs the risk of indicating that the system is approaching lower operational limits when, in fact, inventories are well above demonstrated minimum values.

LOWER OPERATIONAL INVENTORIES

LOI Definition

While having limited benefit for anticipating either a significant retail price excursion or an impending supply problem, the NPC recognizes that there is a valid need for a gauge to help assess current inventory levels. This study recommends replacing both the MOI and minimum observed inventory approaches with a newly defined lower operational inventory, which is defined as follows:

> The lower operational inventory (LOI) is the lower end of the demonstrated operational inventory range updated for known and definable changes in the petroleum delivery system. While not implying shortages, operational problems, or price increases, the LOI is indicative of a situation where inventory-related supply flexibility could be constrained or nonexistent. The significance of these constraints depends on local refinery capability to meet demand and the availability and deliverability of products from other regions or foreign sources.

The LOI definition is conceptually similar to the MOI and the minimum observed inventories currently in use. However, it specifically highlights that the supply system is not necessarily approaching problems when inventories are at low levels and that many other considerations need to be taken into account. In particular, drawing the inventory boundaries at U.S. borders, while understandable from a data collection view, can ignore supply realities. In the case of PADDs I–IV, there are many nearby sources of supply that are "extensions" of U.S. inventories. This makes the analysis of the implications of inventories approaching and/or dropping below any LOI suspect. Given the relative isolation of PADD V, inventories at LOI levels may have more significance. While not indicative of a significant upward retail price movement, as inventories approach the lower part of their operating range, their ability to respond to market imbalances diminishes. This increases the probability that a more significant movement in spot and wholesale prices will be required to balance the market.

LOI Methodology

The methodology for developing the LOIs for major light petroleum products and for crude oil was similar. End-of-month inventory levels reported through the EIA's Petroleum Supply Reporting System (PSRS) were examined for PADDs I–IV in aggregate and for PADD V from 1986 through the first quarter of 1998. These data were used to identify the lower level of month-end operating inventories on a component-by-component basis. In addition, weekly inventory data from the PSRS from 1994 forward were also examined. These data, along with the assessments of the study participants, were used to develop consensus LOIs.

Prior NPC inventory studies used industry surveys as an input to defining the lower operating inventory levels of crude oil and products. The 1988 NPC "Survey of U.S. Petroleum Inventories and Storage Capacity" consisted of five questionnaires asking for information on inventories and tank capacities for crude oil and the four products surveyed, and a sixth questionnaire on the company's assessment of minimum industry operating inventories. Responses to the questionnaires on crude oil and product inventories covered almost 90 percent of inventories reported by EIA for gasoline and crude oil, 98 percent of kerosene jet fuel inventories, and 84 percent of distillate inventories. Relatively few companies attempted to do an MOI assessment for the entire crude oil or product distribution systems. As a result, those data were not published in the 1989 NPC report, *Petroleum Storage & Transportation.*

After reviewing the results of the 1989 *Petroleum Storage & Transportation* study, the 1998 study participants determined that a new survey would have limited value in assessing current lower operating inventory levels and would significantly extend the time required to complete this study. Since other questions raised in

TABLE 2-1

NPC LOWER OPERATIONAL INVENTORIES
(Millions of Barrels)

	PADDs I–IV	PADD V	Total	Change in Total U.S. 1988–1998
Crude Oil*	220	50	270	-30
Gasoline†	160	25	185	-20
Kerosene Jet Fuel	25	5	30	0
Distillate Fuel Oil	76	9	85	0

*Crude oil inventories include an allowance of 15 million barrels of lease stocks in PADDs I–IV and 8 million barrels of Alaskan in-transit and lease stocks in PADD V. These inventories are normally included in crude oil total inventory data but are not an important part of the refining crude oil supply logistics system.

†Gasoline inventories exclude an allowance of 7 million barrels and 3 million barrels in PADDs I–IV and PADD V, respectively, of oxygenate inventories. These inventories are not normally included in gasoline total inventory data but are an important part of the gasoline supply logistics system.

the Secretary's letter did not require a survey, the NPC elected not to conduct an inventory survey as part of this study and rather to rely on available industry data already collected by the EIA for the development of industry LOIs.

LOI Results

Table 2-1 shows the difference between the LOIs developed as part of this study and the MOIs developed in the 1989 study. Crude oil minimum inventories are estimated to be reduced by 30 million barrels (10 million barrels in PADDs I–IV and 20 million barrels in PADD V). Most of the reduction can be attributed to reductions in Alaskan oil in-transit and lease inventories.

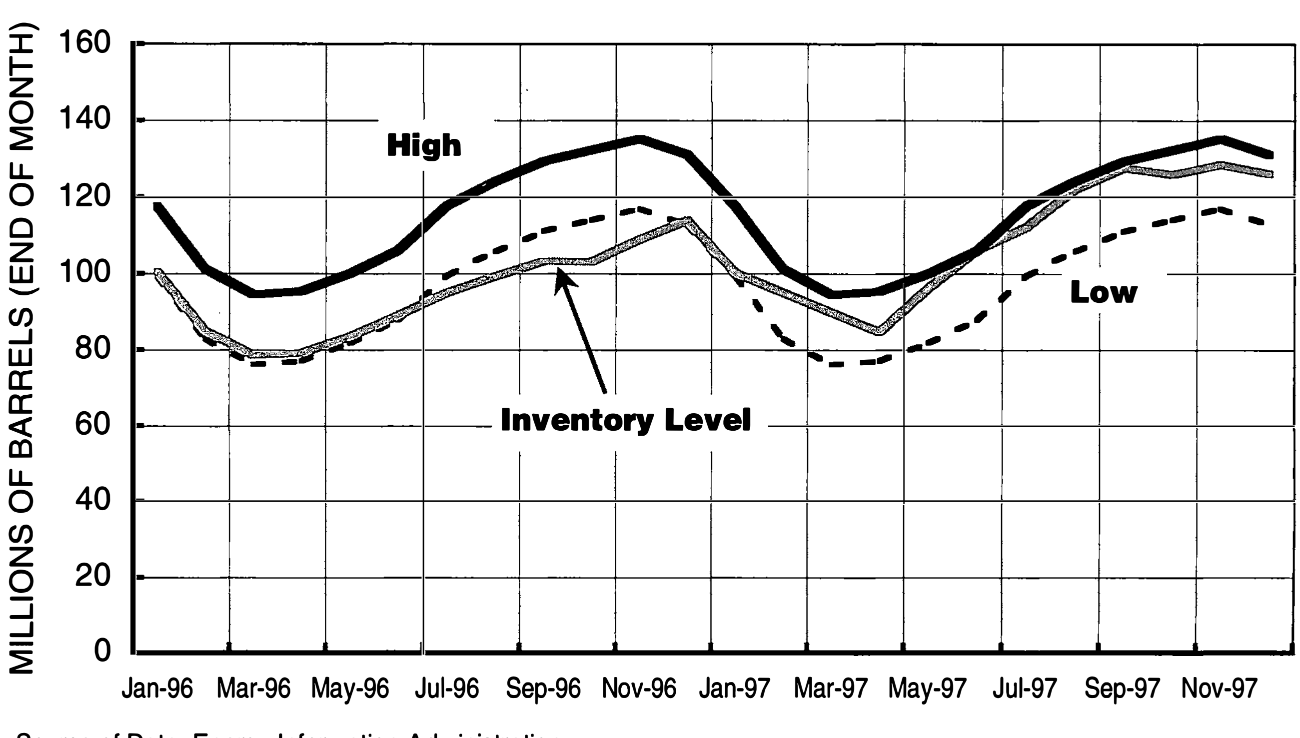
Gasoline minimum inventories are estimated to be 20 million barrels lower in this study (18 million barrels lower in PADDs I–IV and 2 million barrels lower in PADD V). These reductions are primarily the result of lower finished gasoline inventories at terminals, resulting from industry consolidations and improved operating efficiency. In addition, the presence of oxygenates as a nonreported blending component tends to understate available gasoline inventories.

Kerosene jet fuel and distillate minimum inventories are unchanged at the national level, with only minor changes in PADDs I–IV and PADD V.

LOI—One of Many Measures for Assessing Inventory Adequacy

Lower operational inventories relate observed inventory levels to levels that indicate diminished inventory-related supply flexibility, but they provide no information relating inventory levels for any given month to levels that could be considered "normal" for that month. Industry observers use a variety of techniques, from very simple to complex, to analyze seasonal inventory behavior. As an example, the EIA uses a statistical analysis of recent inventory profiles to provide a mechanism for relating observed inventories to normal levels as depicted in Figure 2-18 for distillate inventories in PADDs I–IV.

Figure 2-18. Typical Seasonal EIA Inventory Chart—Distillate, PADDs I–IV.



Source of Data: Energy Information Administration.

The petroleum inventory graphs published by the EIA display inventory profiles as ranges that follow monthly patterns of inventory behavior, adjusted over time to account for changing inventory levels. Typically, the EIA graphs use three years of data, which are then statistically seasonalized to develop a "normal" inventory band. This type of inventory analysis can be particularly important when analyzing inventories of seasonal products such as distillate, but can also provide useful information for analyzing inventories of crude oil and other products. This analysis shows a statistically normal range of variability for inventories, as well as the separation between observed inventories and lower operational inventories. Movement of observed inventories outside the statistical range might be significant, whether or not the observed inventory approaches the LOI.

The EIA approach of analyzing the adequacy of inventories on a seasonal basis is representative of the techniques commonly used to address inventory behavior. While useful in some cases, it is imperative, regardless of the sophistication of the seasonal analysis, that insight and judgment be applied before drawing conclusions about inventory adequacy. This is especially important because key supply sources (e.g., oxygenates and offshore inventories) are typically not included in inventory analysis, while some inventories that have little relevance to supply adequacy (Alaskan crude oil in-transit) are included.

Assessments of LOIs Require Periodic Updates

The petroleum industry is extremely competitive, with many participants, and constantly changes to meet the demands of the market in the most efficient manner possible. Because of changes, assessments made in studies such as this one can become obsolete, sometimes shortly after the data are published. Several product quality initiatives such as Phase II reformulated gasoline are already being implemented in the market or are under discussion. These changes, along with normal market changes, are likely to have significant impacts on the petroleum logistics system operation in the future.

The assessment of lower operating inventory levels has traditionally been done in NPC studies in order to gain broad participation and acceptance of the study results by both industry and government. While this may in fact be the best way to assess inventory behavior, it results in a relatively long and slow process. This study identified several significant items in the LOI assessment, such as Alaskan in-transit crude oil inventories and oxygenates, which are statistical issues rather than judgmental assessments. Adjustments to the 1989 study MOIs could have been made for these types of changes with relative confidence that the resulting data were meaningful, had there been a mechanism in place to address these issues. If the current LOI assessments are to remain useful as the industry changes, they must be periodically updated for known statistical and operational changes. NPC studies are one mechanism for accomplishing these periodic updates. However, it is recommended that the EIA consider other methods for updating LOI assessments between NPC studies. Alternative approaches might use industry statistical committees, consultants, or other groups, to help identify changes that could appropriately be used to adjust this study's LOIs. Obviously, any change would have to be readily apparent and well documented but could provide a more robust assessment of actual industry inventory behavior.

CHAPTER THREE

MARKET DYNAMICS

Market dynamics among supply, demand, and price and the relationship between product inventories and product prices are focal points of this study. Two criteria were used to quantify and categorize product price events for investigation. First, monthly increases since 1973 in retail gasoline and distillate prices in excess of 10 percent above the prior year were identified. Second, retail price increases of 5 percent or greater over four weeks occurring since 1992 were analyzed. Price changes of this magnitude have generated public concern in the past. The analysis shows that most significant widespread product price excursions result from changes in the price of crude oil (crude oil market events) and not from a change in the price spread, the relationship between the value of products and the cost of crude oil (product market events). Nevertheless, there have been a few instances where retail price increases have been the result of product market events.

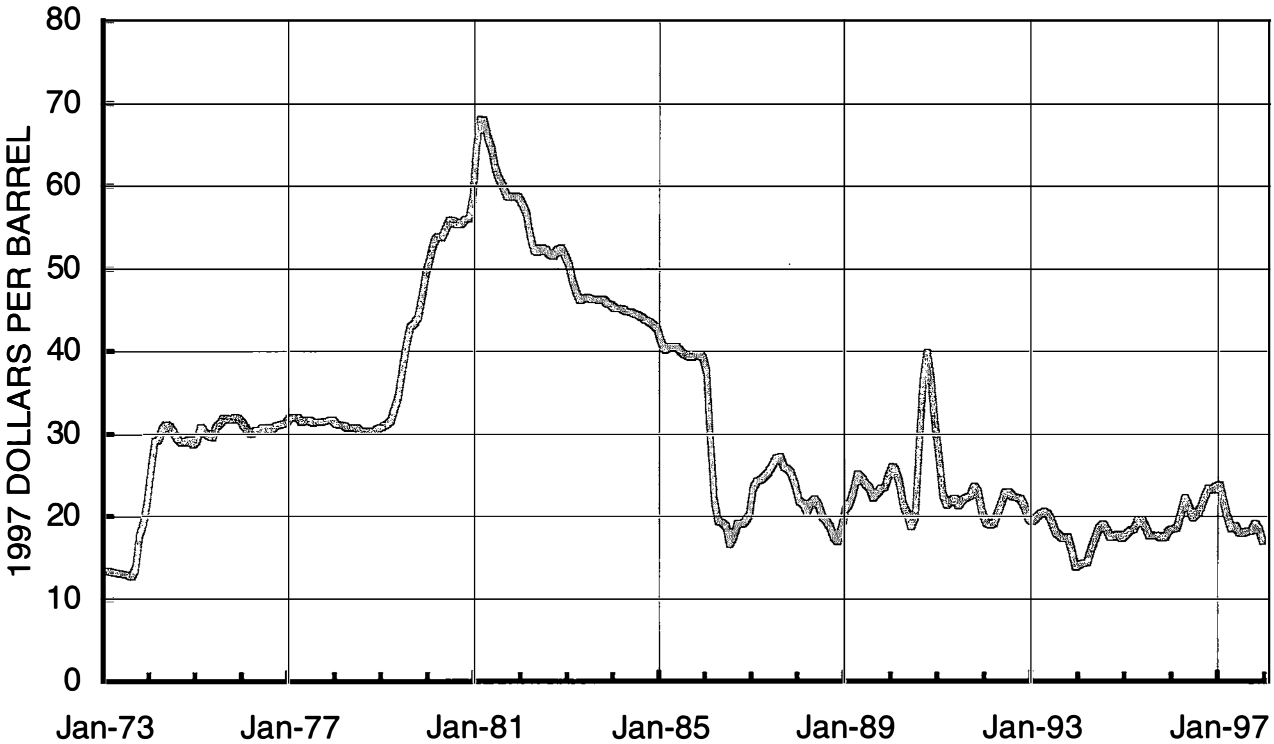
The historical examples meeting the above criteria demonstrate that product market events are resolved fairly quickly. Various factors (other than crude oil price increases) such as peak demand, refinery outages, logistical interruptions, cold weather, and lack of import availability have contributed to historical product price increases. During these product market events, price increases are frequently accompanied by rapidly dropping inventory levels as demand exceeds supplemental sources of supply for short periods of time. The degree of spot and wholesale price response during these events is a function of the market's perception of the magnitude and duration of the market imbalance. Normally, it takes several factors acting in the same direction to cause product markets to tighten for a sufficient period of time to raise retail prices to a level that causes consumer concerns.

Instances of retail product price increases in excess of 10 percent above the prior year are dominated by crude oil market events. Retail price increases greater than 5 percent for gasoline and distillate over a four-week period have only occurred eight times since 1992, and most of these were in conjunction with crude oil price increases. While price increases can normally be attributed to events, there are many instances of major events that do not result in a significant price increase to consumers. For example, events that disrupted supply but did not cause consumer prices to increase over the 5-percent threshold include Hurricane Andrew in 1992, which shut down many of the Gulf Coast refining facilities, and the Colonial Pipeline break in 1994.

CRUDE OIL, KEY DRIVER OF U.S. PRODUCT PRICES

Product prices can and do fluctuate seasonally and in response to perceived market conditions, but it is abundantly clear that the overwhelming factor in the level of consumer product prices is the price of crude oil. Because crude oil is a world commodity, U.S. crude oil prices respond to world events rather than only those isolated to the United States. Figure 3-1

Figure 3-1. U.S. Monthly Refiner Crude Oil Acquistion Cost.



Source of Data: Derived from Energy Information Administration Data.

illustrates the average U.S. refiner monthly crude oil acquisition cost from January 1973 through December of 1997 in constant 1997 dollars per barrel. This cost is the average raw material price paid by the U.S. refining industry and, since the lifting of domestic crude oil price controls in 1981, is indicative of world prices.

Figure 3-2 plots those instances where the crude oil price exceeded the prior year's price by 10 percent or more. The graph highlights seven significant spikes since 1973: three resulting from conflicts in the Middle East, three resulting from crude oil price recovery from very low levels in prior years (1986, 1988, and 1993), and the 1996 price excursion that resulted from a confluence of smaller events all in the same direction. Figure 3-3 plots incidences of retail gasoline and retail heating oil price excursions in excess of 10 percent over the prior year, along with the crude oil data. The chart shows that with few exceptions year-to-year product price changes greater than 10 percent have been driven by the price of crude oil.

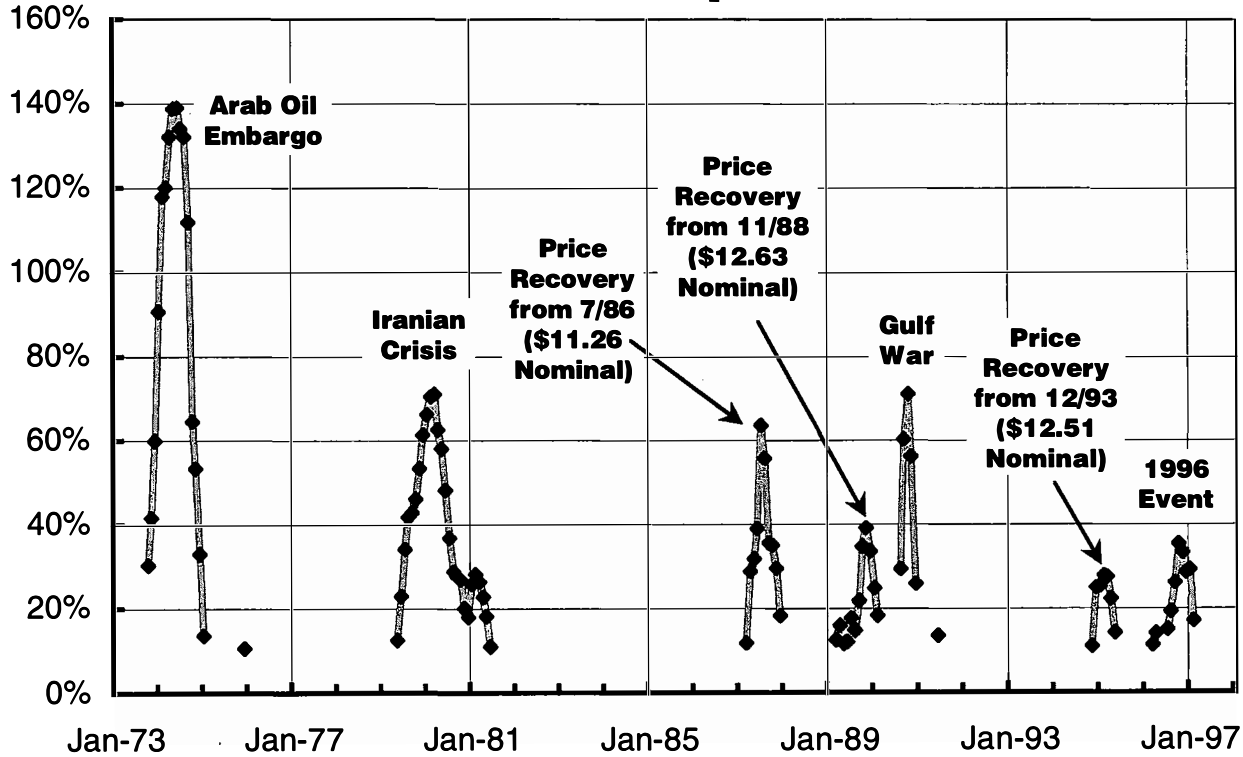
PRODUCT PRICES

Separating Crude Oil Market from Product Market Influences on Price

Figure 3-4 plots the total monthly retail gasoline price since 1973, in 1997 dollars. It also depicts retail gasoline price less the cost of crude oil. Gasoline prices excluding crude oil do vary, but the magnitude of the deviations is significantly less than the deviations caused by crude oil market fluctuations. As shown on the chart, there has been a slow downward trend in the real cost of retail gasoline including taxes but excluding crude oil.

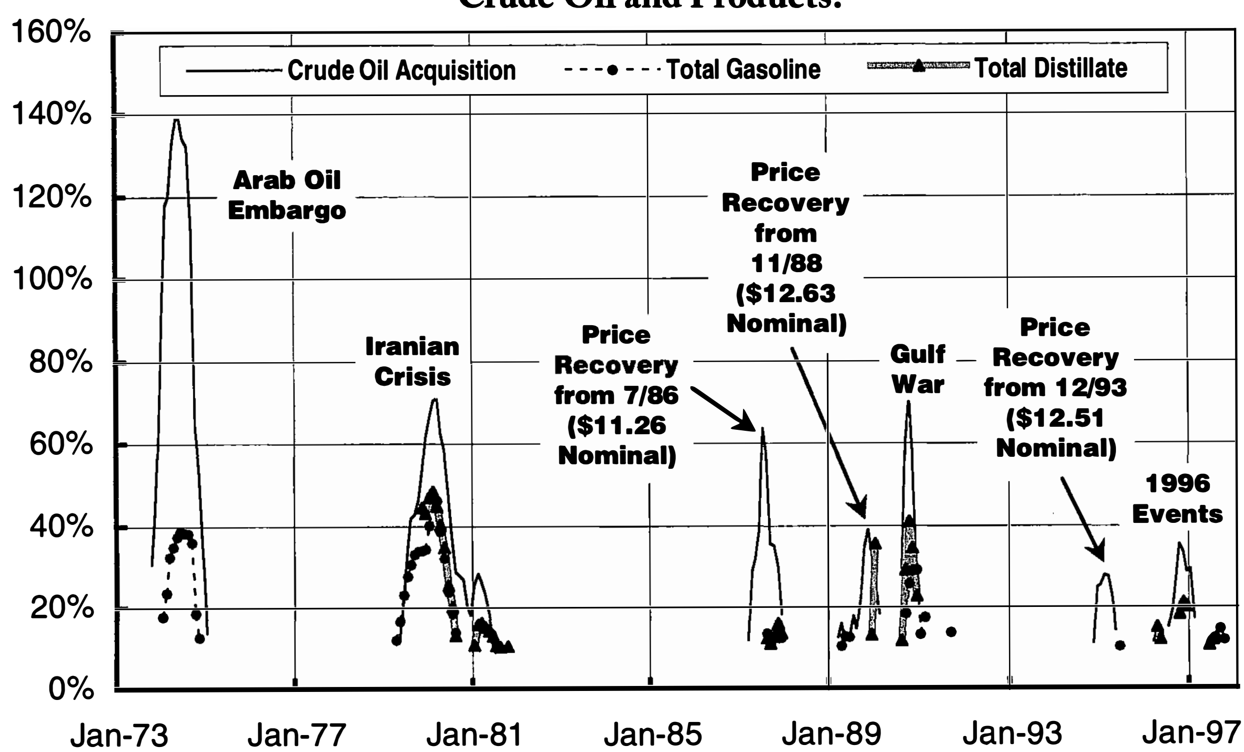
Spot and wholesale prices move constantly and provide the commercial market signals that allow supply to balance demand. The changes in spot product prices can best be understood by separating the total price into two components: crude oil price and the difference between the product price and the crude oil price (spread). Spot price spreads (spot product price minus crude oil price) capture the

Figure 3-2. Instances of >10% Change in Price vs. Prior Year–Refiner Crude Oil Acquisition Cost.



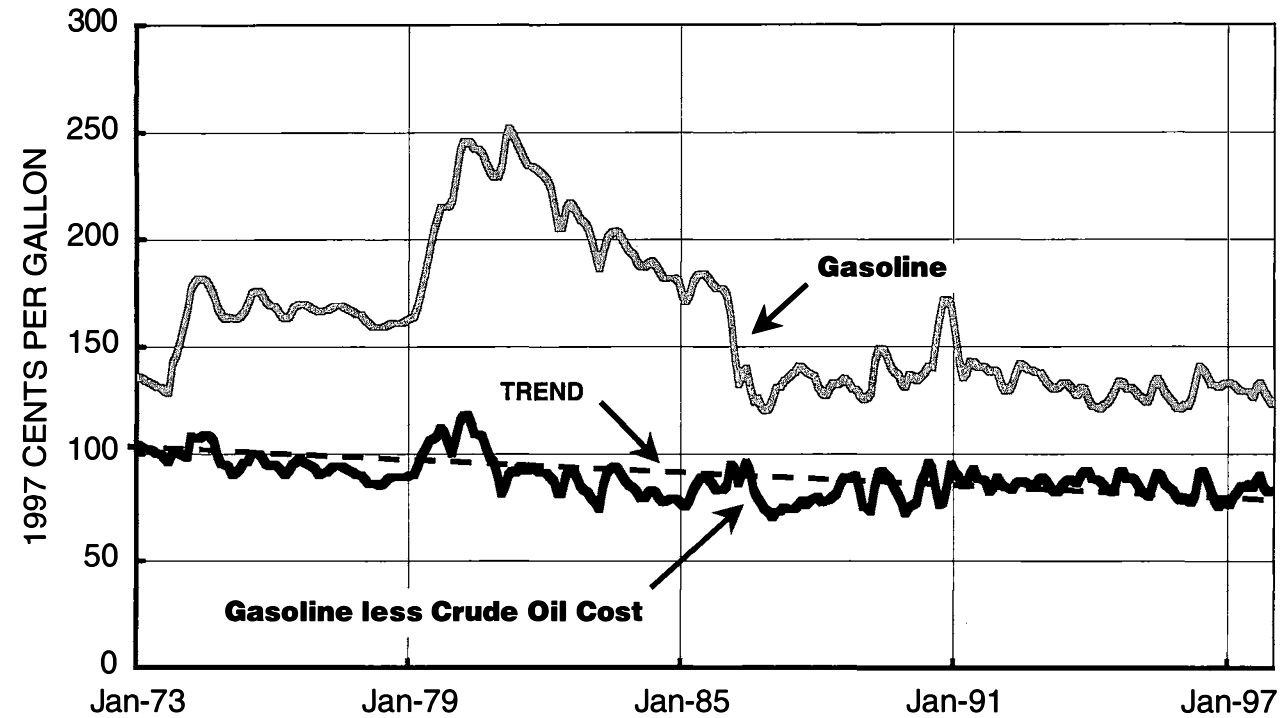
Source of Data: Derived from Energy Information Administration Data.

Figure 3-3. Instances of >10% Change in Price vs. Prior Year–Crude Oil and Products.



Source of Data: Derived from Energy Information Administration Data.

Figure 3-4. Monthly Average Retail Gasoline Price (Including Taxes).



Source of Data: Derived from Energy Information Administration and Bureau of Labor Statistics Data.

current value of products relative to crude oil, and changes in this spread provide the incentive for refiners to alter production. Gasoline and distillate price spreads (Figure 3-5) exhibit highly seasonal patterns reflecting the nature of their associated product demand. The spreads are the primary cause of the opposite seasonal patterns seen in retail gasoline (Figure 3-6) and heating oil market prices.

The spot gasoline spread is usually at its minimum in December when gasoline demand is low and gasoline inventories are nearing their peak as a result of the gasoline produced while meeting winter distillate needs. The gasoline spread begins to increase as winter production falls off. The spread climbs rapidly as spring turnarounds result in drawdown of much of the winter product inventory build, and refineries begin ramping up gasoline production to meet summer demand. As gasoline production reaches high seasonal levels, gasoline spreads generally peak around May. A second peak frequently occurs again in August with the last surge in summer demand, before falling back to the December low point.

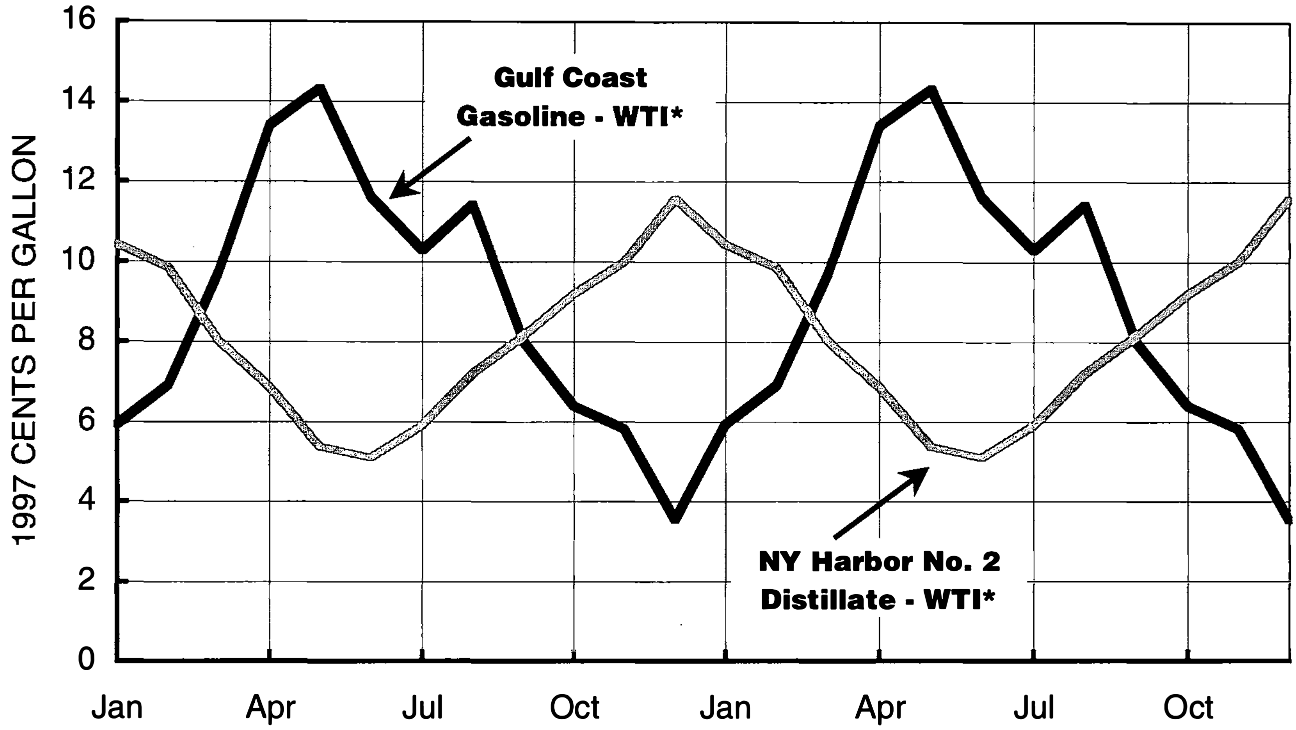
Distillate spreads usually move in the opposite direction of gasoline spreads. Distillate spreads generally reach their minimums in June or July and climb in the fall. Distillate spreads peak during the high winter demand season before beginning their seasonal descent.

The Relationship between Inventories and Price Changes

Product inventory changes serve as a measure of the physical market balance between primary demand and primary supply sources (production and product imports). If inventories deviate significantly below expected seasonal norms, spot product price spreads generally increase. If an event occurs that causes further inventory reductions, additional spread increases will likely occur. Larger spreads increase the incentive for additional supply to arrive. Conversely, inventories higher than expected seasonal norms generally reduce product spreads.

An analysis of spot gasoline prices performed by EIA found that "stock levels of gasoline relative to normal levels seems to be the

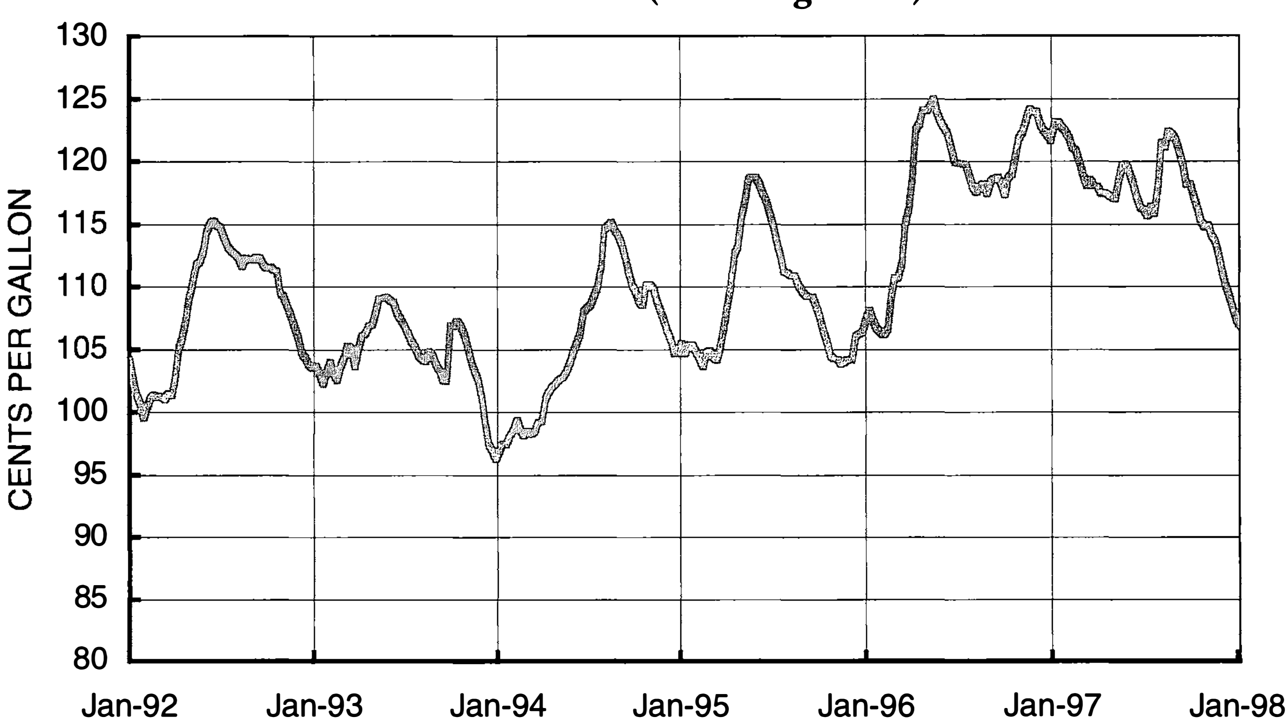
Figure 3-5. Gasoline and Distillate 10-Year Average Spot Price Spreads.



*WTI—West Texas Intermediate Crude Oil.

Source of Data: Energy Information Administration.

Figure 3-6. Weekly Regular Conventional Retail Gasoline Price (Including Taxes).



Source of Data: Energy Information Administration.

most important variable in explaining short-term gasoline spread movements.... [In] essence, stocks are a yardstick for short-term, supply-demand balance tightness, and the supply-demand balance seems to be the most significant market factor explaining gasoline spread variations under and over the normal seasonal swings."[1] It is important to understand that product inventory changes are not the cause of spot and wholesale price movements, but, rather, a reflection of the current supply/demand balance in the primary system. Inventory changes together with all other market information ultimately result in price changes.

A significant amount of commercial activity in crude oil and petroleum product markets calls for delivery in future time periods. This activity is referred to as the forward market. While there is a large variety of forward market transactions, market participants most commonly buy and sell crude oil and petroleum products for delivery during specific future months. As a result, a series of spot prices can be observed for forward market transactions over a series of subsequent months. The most visible of these series in the United States are for the futures contracts for crude oil and petroleum products traded at the New York Mercantile Exchange (NYMEX). The transaction prices at NYMEX are widely disseminated, and thus the resulting spot price series for crude oil, unleaded gasoline, and heating oil are publicly observable.

Forward markets play an important role in inventory decisions. When spot prices for future delivery are higher than spot prices for current delivery, the market is said to be in contango. If the price for future delivery is sufficiently above the price for current delivery, there is an incentive to build discretionary inventories. As inventories increase, storage costs rise as increasingly costly storage options are utilized. The magnitude of a contango market is limited by the economics of storage. Ultimately, when all available storage is filled, production and imports can no longer exceed demand. The period from mid-1997 to mid-1998 is illustrative of a contango market.

[1] John Zyren, "What Drives Motor Gasoline Prices," Petroleum Marketing Monthly, Energy Information Administration, DOE/EIA-0380, June 1995, p. xviii.

Conversely, when spot prices for future delivery are lower than spot prices for current delivery, the market is said to be in backwardation. Backwardated prices provide economic incentives to reduce discretionary inventories. The relationship between backwardation and inventory levels can have a compounding effect. As inventory declines, prices for current delivery can increase further, resulting in greater backwardation. When there is a relatively low level of inventories and the market is in backwardation, cause and effect are difficult to determine. In the short term, the magnitude of a backwardated market is limited only by the marginal cost of acquiring incremental supply for current delivery. The second quarter of 1996 is illustrative of a severely backwardated market. Ultimately, as price for current delivery increases, supply and demand respond and balance is restored.

Forward markets reflect the complex relationship between crude oil and petroleum products. The market incorporates consideration of a number of factors such as current spot price relationships between crude oil and products, forward curves (price series over a future time period) of this relationship, and direct and opportunity costs for storage. Spot markets are constantly changing, reflecting a balance of individual views of all market participants.

How Spot Market Changes Pass Through to Retail

Spot price spreads can move rapidly as markets balance. Retail prices neither rise nor fall as rapidly as spot prices. EIA has demonstrated that retail price changes lag behind spot price changes.[2] This has the effect of dampening and delaying the price swings at the retail level[3]

[2] Energy Information Administration, *Assessment of Summer 1997 Motor Gasoline Price Increase,* DOE/EIA-0621, May 1998, pp. 55–57 and Appendix E.

[3] The EIA analyzed the relationship between changes in weekly retail prices reported to EIA (Form EIA-878) and changes in weekly average spot prices. In general, results showed about 50 percent of a spot price change was passed through to retail in four weeks, with an additional 30 percent pass-through occurring in the next four weeks. That is, if weekly average spot prices increase 10 cents from one week to the next, retail customers would only have seen about 5 cents of the increase four weeks later, and about 8 cents of the increase eight weeks later.

as illustrated in Figure 3-7. This market phenomenon is important, as spot prices provide the necessary price incentive to rebalance supply and demand, often before a significant price change reaches the retail consumer.

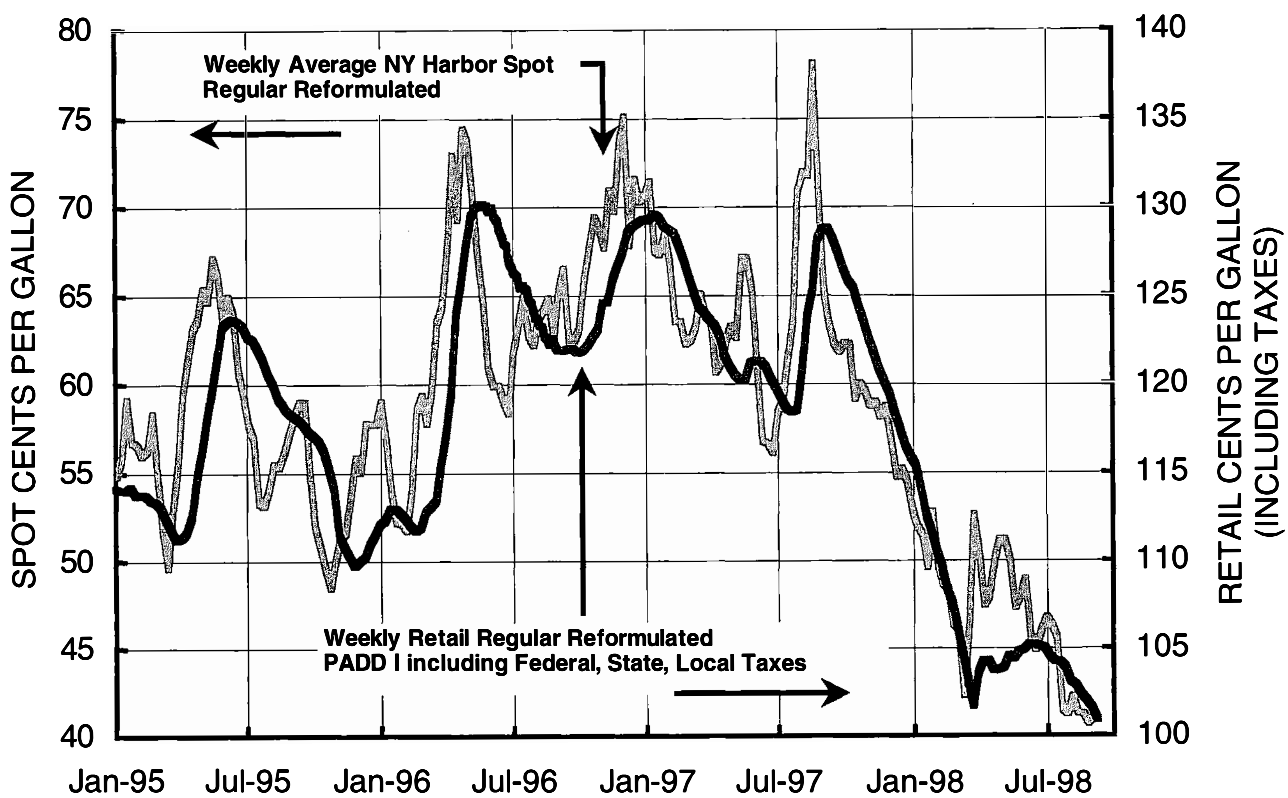
HISTORICAL PRICE INCREASES

When retail prices rise rapidly, whatever the starting point, consumers of gasoline and home heating oil can become very concerned. Fortunately, large rapid price increases in retail markets do not happen frequently. Increases of as little as 5 percent nationally over a short time period have been of concern to consumers. However, since the beginning of 1992, national average retail conventional gasoline prices have increased 5 percent (5 cents or 6 cents per gallon) or more during a four-week period only five times (Figure 3-8), and heating oil only three. When the national average price increases 5 percent, some local areas will have increased more and others, less.

Price increases stem both from the product and crude oil markets. Product market events can cause quick price increases, but typically don't result in long-lasting changes. Of the eight historical price increases larger than 5 percent in gasoline and heating oil, only three stemmed from product market events alone. Three were the result of crude oil price increases combined with product market events, and two were essentially due to changes in crude oil price alone.

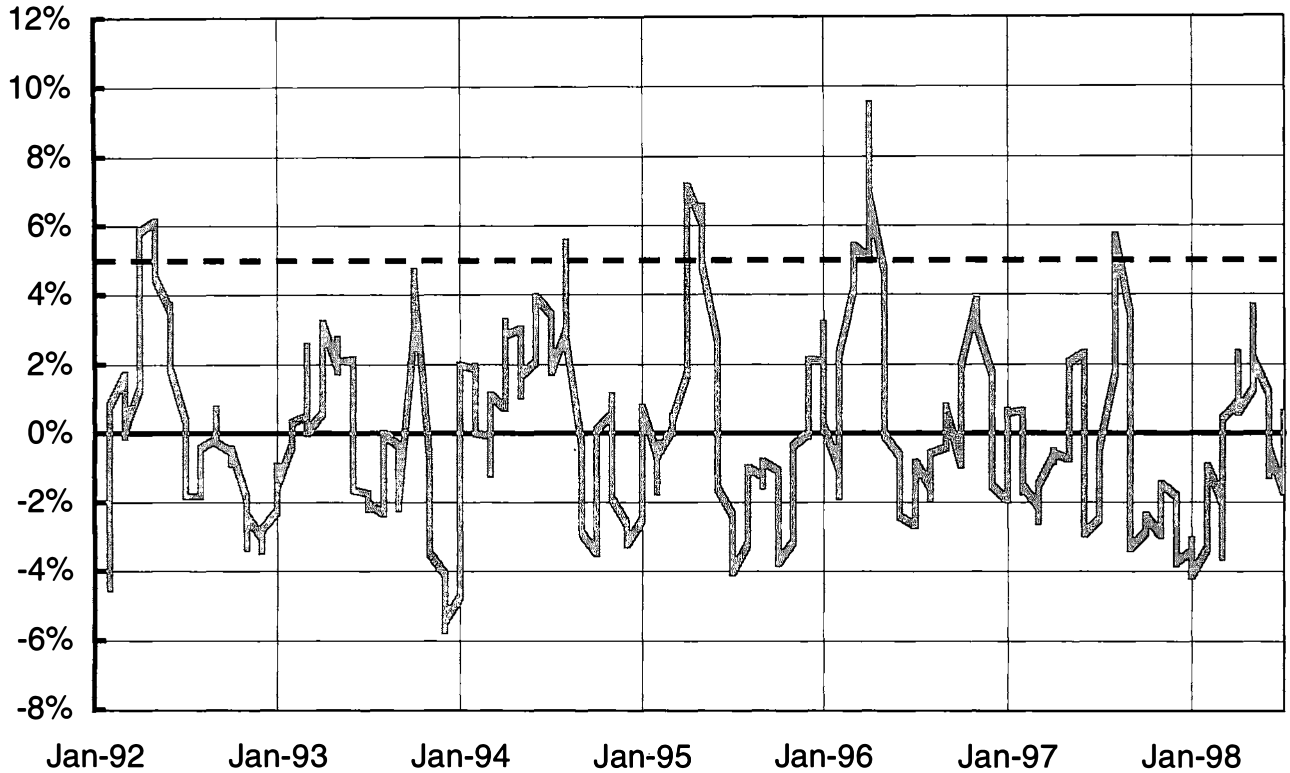
The spot price spreads for gasoline and distillate help to highlight price increases caused by the product markets. While consumers do not immediately see spot spread movements in their retail price, prolonged spread changes ultimately impact retail prices. Figures 3-9 and 3-10 show the monthly average spot distillate and gasoline spreads along with the ten-year averages for each month to provide an indication of average seasonal behavior versus the actual.

Figure 3-7. Lag Between Retail and Spot Reformulated Gasoline Price—PADD I (East Coast).



Source of Data: Energy Information Administration.

Figure 3-8. Four-Week Percentage Change in U.S. Average Retail Gasoline Price.



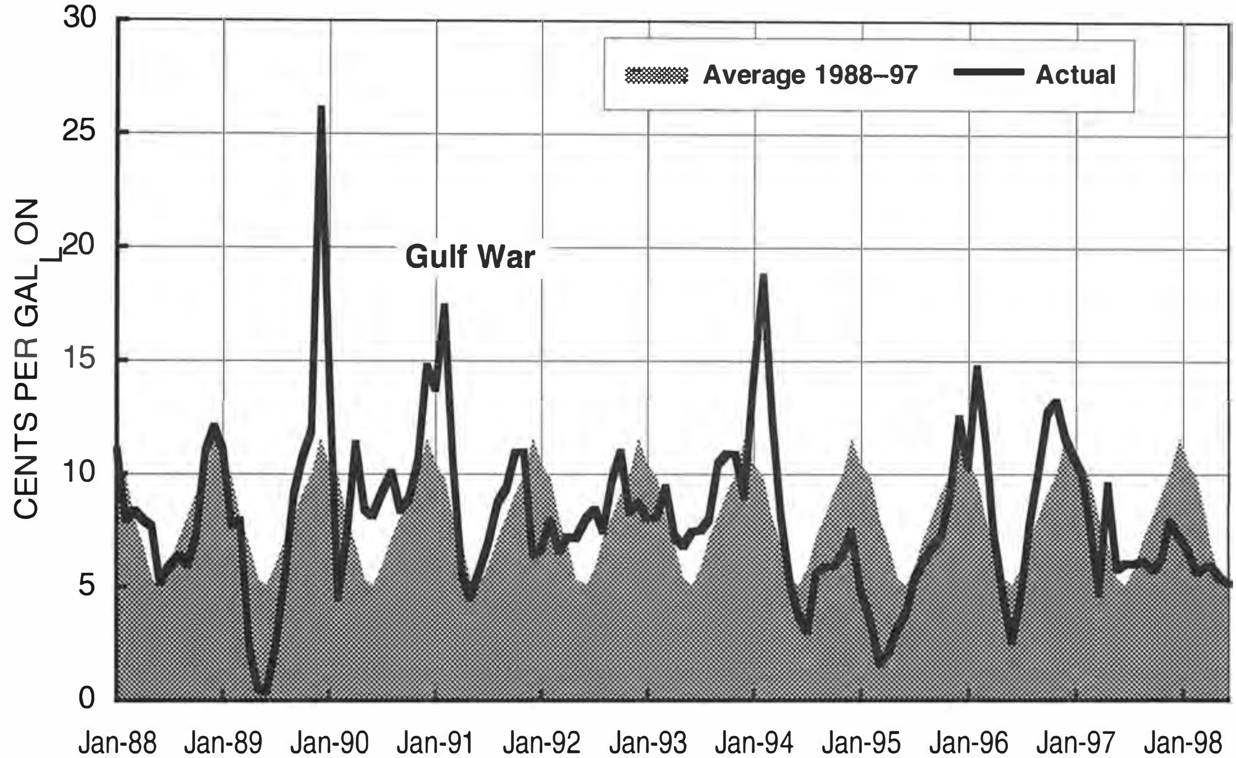
Source of Data: Energy Information Administration.

Figure 3-9 shows two outstanding distillate-spread increases apart from the Gulf War. By far the most dramatic spot spread increase (and resultant retail price increase) was for distillate in 1989. Average monthly residential heating oil prices rose 23 percent between November and December in PADD I, climbing from $0.89 per gallon to $1.10. Retail prices then rose an additional $0.08 per gallon, or 7 percent, in PADD I in January. Inventories were lower than the prior five-year average going into the 1989–90 winter season,[4] and the weather in December was the coldest in 102 years. Heating fuel demand surged. In addition, several refineries on the Gulf Coast experienced outages from freeze-related problems. In December 1989, the loss of supply and increased demand resulted in a distillate inventory reduction of 14 million barrels. This reduction was in contrast to the prior five-year average 0.4 million barrel build and completely erased the 1989 pre-winter inventory build. January weather was significantly warmer than normal and inventories increased by 12 million barrels, in contrast to a more normal January inventory reduction of about 10 million barrels, alleviating concerns about future supply and collapsing spot spreads to below normal seasonal levels.

The three U.S. average heating oil price increases greater than 5 percent since 1992 are discussed in detail in the first text box at the end of this chapter. Only one was driven mainly by distillate spread increases, which stemmed from cold weather and some supply problems (January 1994). The remaining two, December 1995 and fall 1996, resulted from both crude oil price and spot distillate spread increases. During these price events, the spot spread contribution was much less significant in retail price increases than in January 1994.

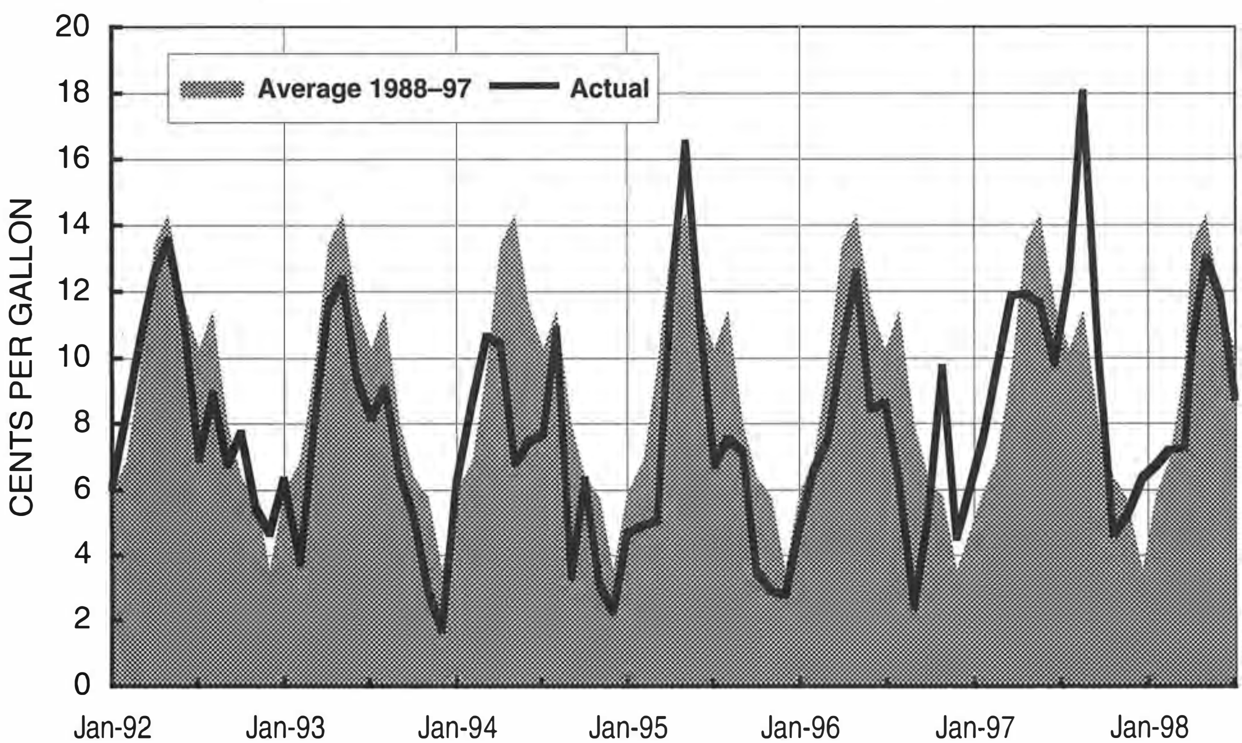
[4] In 1989, end-of-November distillate inventories were 119.7 million barrels, which was more than 23 million barrels lower than the prior five-year-average ending-November inventories of 143.1 million barrels.

Figure 3-9. New York Harbor Spot Distillate Minus West Texas Intermediate Crude Oil Price.



Source of Data: Energy Information Administration.

Figure 3-10. Gulf Coast Spot Gasoline Minus West Texas Intermediate Crude Oil Price.



Source of Data: Energy Information Administration.

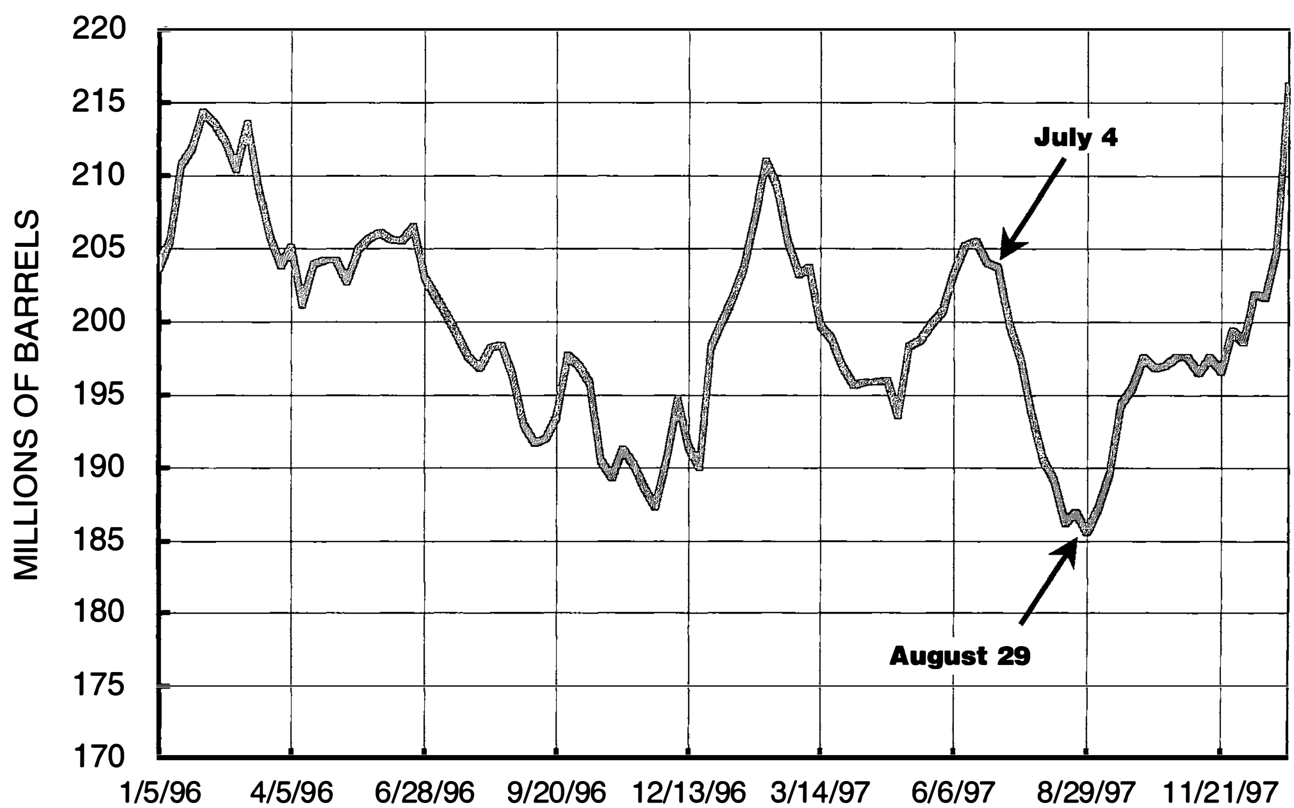
The spot gasoline spread chart (Figure 3-10) shows only one period, the summer of 1997, that stands out significantly from the ten-year average. Crude oil prices were basically unchanged during late summer 1997, and retail prices increased as a result of the spread increase only. The only other time when gasoline spread contributed significantly to one of the five highlighted retail-price increases was during spring of 1995. Spreads were lower than the ten-year average that year as the new reformulated gasoline (RFG) program got underway. Spot gasoline spreads rose rapidly before falling back below seasonal norms for the second half of the year. Two of the remaining three gasoline-price increases were due to crude oil price increases on top of typical seasonal gasoline spread increases (spring 1992 and spring 1996). The last retail gasoline-price increase over 5 percent, in August 1994, was due to both crude oil price increases and gasoline spread changes slightly larger than the ten-year average. These events are discussed in more detail in the second text box at the end of this chapter.

Dynamics of a Spread-Driven Price Increase—Summer 1997

Gasoline prices often rise slightly from July to August, as the last surge in summer driving occurs. In 1997, however, the price increase was large enough to draw public attention. From the end of July to August 20, gasoline spot prices rose about 20 cents per gallon. At the same time, conventional retail prices rose about 7 cents per gallon and retail RFG increased about 11 cents per gallon. Crude oil prices were relatively flat across this period, with the price increase due to the gasoline spread.

At the end of June 1997, gasoline inventories were slightly below seasonally expected norms, but gasoline spreads were below their ten-year average. With the weaker spreads, production and imports reduced slightly from June to July. In early July, withdrawals from the primary supply system increased significantly, resulting in declining weekly gasoline inventories (Figure 3-11). Initially the market showed little response, but inventories continued their

Figure 3-11. Weekly Total Gasoline Inventory.



Source of Data: Energy Information Administration.

Heating Fuel Price Increases at the Retail Level

Over the 1992–97 period, consumers have experienced three occasions when heating oil prices increased 5 percent or more over a four-week period.

- In January 1994, a cold wave drove up demand, interfered with barge traffic, and caused some refinery problems. Inventories began the month above historical seasonal norms. High demand and supply disruptions resulted in a removal of 23 million barrels from primary inventories. This compares to the prior five-year average 8-million-barrel draw for January. Distillate inventories were left at 4 million barrels below historical seasonal norms by month end, which was the second lowest ending January stock level since 1981. PADD I residential heating oil price went from $0.94 per gallon at the beginning of January to almost $0.99 by the end of the month. They peaked at $1.02 per gallon in mid-February before falling.

- The warm first quarter of 1995 left end-of-season distillate inventories high, and they stayed seasonally high through much of the summer. As fall approached, forward markets were relatively flat, which discouraged inventory building. Inventory levels in December 1995 were more than 8 million barrels below the prior five-year average inventory levels. Cold weather in the Northeast and Midwest increased demand quickly, and heating oil prices rose from $0.94 at the beginning of December to $1.04 by the middle of January. Crude oil prices also increased slightly from November to December, adding to the price rise. Distillate inventories fell over 5 million barrels during December, compared to the prior five-year average 3-million-barrel draw. With inventories lower than normal and cold arriving early in the season, the distillate spread increased and the production response ended the price surge fairly quickly.

- Retail heating oil prices also increased by more than 5 percent in the fall of 1996, a time period that is discussed in more detail in Chapter Four. Crude oil prices climbed steadily through the fall, and markets were strongly backwardated. August ending inventories were more than 20 million barrels below the prior five-year August average, and spot distillate spreads increased above the ten-year average. The crude oil and product markets together caused monthly average prices to rise from $0.88 in August to $0.94 in September (7 percent), and to increase another 10 percent to over $1.03 in October. Of the $0.15 increase from August to October, only $0.02 or $0.03 of the rise was due to higher than normal seasonal spreads. The remainder was the result of crude oil price and average seasonal spread increases.

Conventional Gasoline Price Increases at the Retail Level

Over the 1992–97 period, there have been five times when U.S. average retail gasoline prices increased 5 percent or more over a four-week period.

- The first increase was in the spring of 1992. Retail prices rose fairly steadily from $1.01 per gallon at the end of March through the end of June when they peaked at almost $1.15. Crude oil price increases on top of the average spring spread were the main reasons behind the rise.
- The next such increase was in early August 1994, when retail gasoline prices rose from $1.08 in early July to almost $1.15 by the first week of August. Most of the increase occurred during the last week in July and the first week in August when fires affected two East Coast refineries. Spot gasoline spreads increased from below ten-year average levels to average. Gasoline inventories were above the prior five-year average for that time of year, and only dropped about 5 million barrels during early August. Prior to the fires, gasoline prices had been rising as a result of rising crude oil prices. Crude oil prices dropped shortly thereafter, pulling gasoline prices down. Spreads fell below average again.
- The third increase was during the spring of 1995, the first year of the RFG program. Between the middle of March and the second half of May, retail prices climbed over $0.14 per gallon, while spot prices increased over $0.19. Most of the price increase derived from product market factors, although crude oil prices also contributed $0.03 to $0.04 to the increase. Several refinery problems on both the East Coast and West Coast and lower imports, as a result of the complexities of the new RFG program, caused a brief price increase. This occurred during the time when refineries were coming out of maintenance and increasing production to meet growing summer demand. Spreads fell to below seasonal norms during the second half of the year.
- The fourth increase was during the spring of 1996. During this time, crude oil prices increased as spot gasoline spreads exhibited their normal seasonal behavior. Although gasoline inventories were low, the gasoline spread stayed within a penny or two of the ten-year average seasonal levels.
- The last increase in that time period was during the summer of 1997. This was strictly a spread-driven increase, and one of the only purely product market driven increases that has occurred on a U.S.-wide basis.

sharp descent to end July at near-record lows. In total, inventories fell over 14 million barrels in July, when the prior five-year average July drop was only 5 million barrels. Spreads began to increase as inventories fell. Approaching August, usually the peak demand month of the year, gasoline inventories were below the expected seasonal norm, and U.S. refineries were operating at high utilization levels (97.1 percent).

At the end of July and in early August 1997, several events occurred: operating problems at a major Gulf Coast refinery on top of a continued shutdown of a major East Coast refinery's fluid catalytic cracking unit; operating problems at two of PDVSA's export refineries and a subsequent declaration by Venezuela of force majeure on several cargoes of gasoline scheduled for August delivery to the United States; and three major refineries in Europe reporting catalytic cracking unit problems. While some of these reported problems ultimately had little impact on production, the uncertainty at the time of the events added to market concerns. Inventories continued to drop through August, ending the month at the lowest level recorded since 1981. Spot gasoline spreads rose through the first part of August and peaked on August 20. While spot prices for current delivery were sometimes more than 10 cents per gallon higher than European prices, strong backwardation made it difficult to hedge cargoes leaving Europe for the United States. The increased spreads were reflected in retail prices in August and the first part of September. After Labor Day, with production and imports exceeding demand, inventories began to rise and spreads fell back to seasonal norms.

This price excursion, which lasted about six weeks, was one of the longer lasting retail price events caused by nonseasonal spot spread increases. Usually, product market events are resolved more quickly.

Chapter Four

Market Cycles in Extreme—1995 to Mid-1998

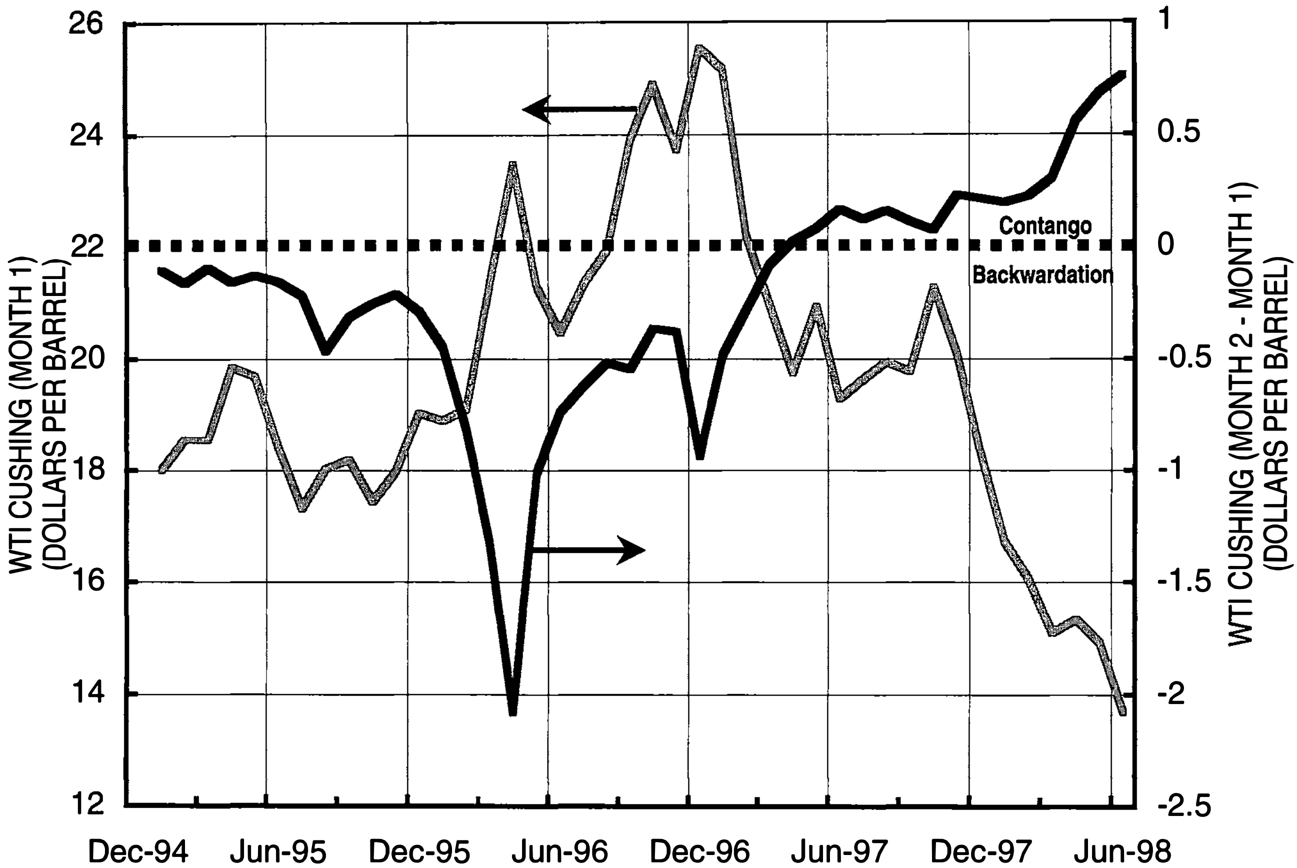
The flexibility of the U.S. petroleum logistics system and the inventory response to events has been demonstrated during several extreme situations. At these times, inventories moved outside typical ranges in response to market signals. These episodes are also frequently characterized by retail price changes. When such events are analyzed retrospectively, the logistics system balanced as expected in a complex, competitive industry. During these events, questions regarding price and industry efficiency are often raised.

A review of the period from 1995 through mid-1998 illustrates situations where inventories were driven to levels near both the minimum and the maximum of their operating range. This period covers two distinct patterns of inventory behavior—1995 through early 1997, a period of inventory reduction, and late 1997 through mid-1998, a period of inventory accumulation. Crude oil prices moved dramatically through this time frame, increasing from about $18 per barrel in mid-1995 to about $25 per barrel at the end of 1996 and then falling to less than $14 per barrel in June of 1998.

Prices for current delivery of petroleum reflect the market's perception of surplus or shortage, as well as other factors. When prices for current delivery move quickly, the prices for future delivery often do not move as fast. This is illustrated in Figure 4-1, which shows the current crude oil price (West Texas Intermediate at Cushing, basis NYMEX first future month) along with the difference between the price for crude oil delivery in the first and second future months. When current delivery prices are relatively stable, as in most of 1995 and from April to October of 1997, the difference between the price for future delivery and current delivery also tends to be stable. When the current price moves quickly, however, as in most of 1996 and from late 1997 through June 1998, the difference between future and current prices can change dramatically.

As discussed previously, a critical factor in inventory decisions is the relationship of forward to current markets. When forward market values are less than current values, the market is said to be in backwardation, and there is a disincentive to accumulate or hold inventory. When the situation is reversed (forward markets higher than current markets), the market is said to be in contango, and inventories will generally build if the forward markets

Figure 4-1. Current and Future Delivery Crude Oil Price.



Source of Data: New York Mercantile Exchange (NYMEX).

will cover the cost of storage. The strong relationship between inventory change and the forward market is illustrated in Figure 4-2, which shows the difference between the forward and current prices for crude oil along with the U.S. inventories of crude oil and major light petroleum products.

A number of detailed studies and analyses have been performed on the market dynamics and inventory behavior observed during the 1996 period. This study does not attempt to repeat these analyses but rather highlights some of the key events that occurred across the time frame and the market responses. While significant price and inventory changes have occurred in prior periods, they were normally the result of a large event such as a war. The period from 1996 through early 1997 is unusual because the market was driven by a number of smaller events that happened to drive the market in the same direction. Further information on the market and inventory responses across this time period can be found in *How Much Oil Inventory Is Enough?* by Heather Rowland (November 1997, Energy Intelligence Group).

THE PERIOD OF INVENTORY REDUCTION: THE PHASE FROM 1995 THROUGH EARLY 1997

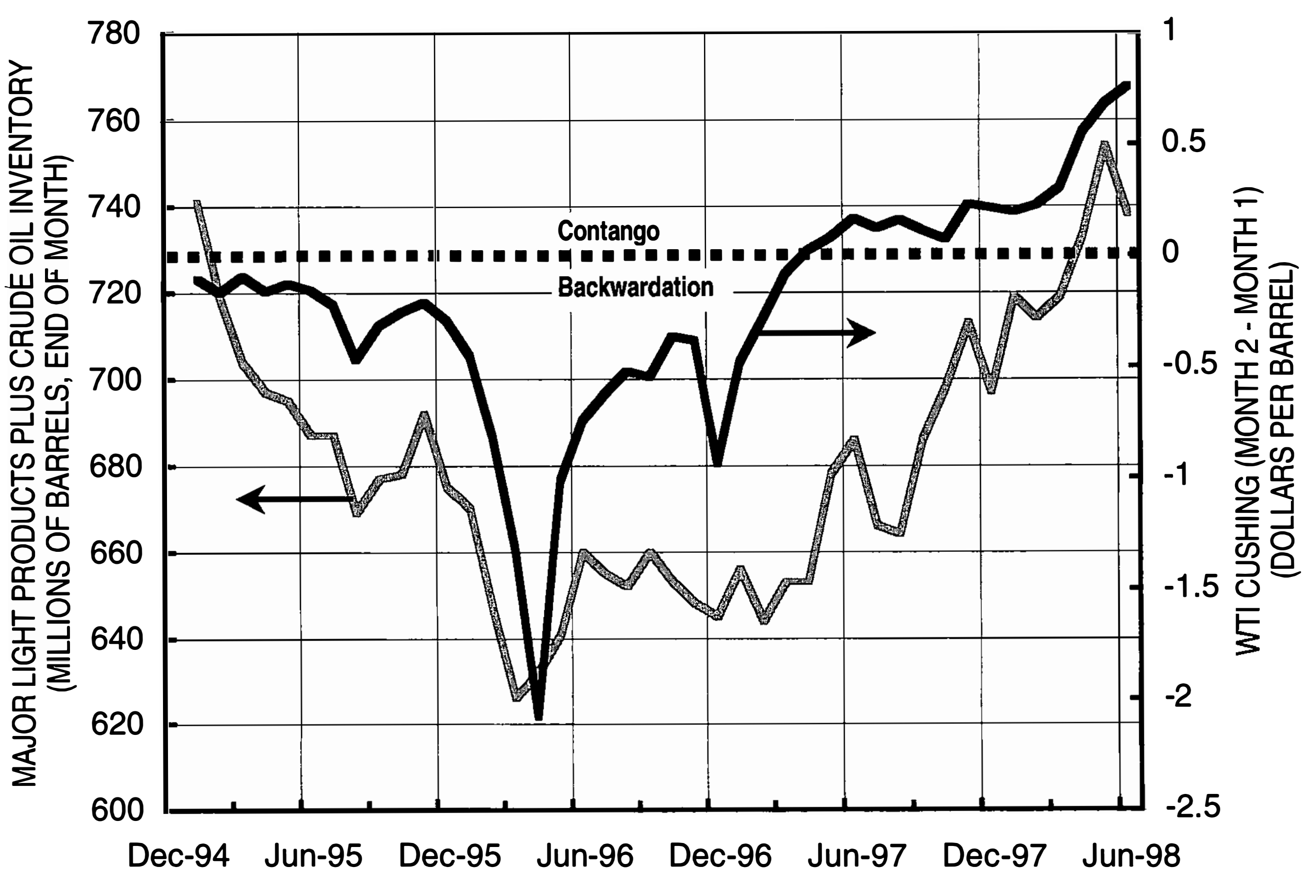
In 1995, U.S. petroleum product demand growth continued and forward markets were slightly backwardated, eliminating the incentive to hold discretionary inventory. Late in the year, storms disrupted Gulf of Mexico crude oil production and shipping. Mexican crude oil shipments to U.S. refineries were significantly reduced, which resulted in a reduction of U.S. crude oil inventories. Inventories that had increased from August through November were drawn sharply in December 1995; consequently, crude oil inventory levels at the beginning of

1996 were below those experienced over the last two decades. Crude oil prices (West Texas Intermediate at Cushing) averaged about $19 per barrel in December, an increase of about $1 per barrel from November but still below the peak price earlier in 1995.

Early in 1996, Gulf Coast refineries were forced to reduce production because of continued crude oil delivery problems. In addition, a major East Coast refinery was temporarily closed. Colder than normal weather, continuing from late 1995, increased heating oil consumption. U.S. crude oil and major light petroleum product inventories were at their lowest levels in recent history at the end of March 1996. Prices for current crude oil delivery rose, reaching an average cost of about $23.50 per barrel in April, to reflect disrupted supply and strong demand. However, the prices for future delivery did not rise as quickly because the anticipated return of Iraqi crude oil was expected to rebalance the market. Consequently, a strongly backwardated market existed, as shown in Figure 4-2.

During the summer of 1996, petroleum inventories recovered from the end-of-March lows. Crude oil prices fell into the $21 to $22 per barrel range by summer, reducing some of the backwardation in the market. Because there was no incentive to build discretionary inventory, the seasonal build was lower than normal. In addition, there was an atypical incentive to move low-sulfur distillate to Europe resulting from changed European diesel specifications and low European inventories. Fall commenced with inventories below the low end of historical seasonal ranges. Current crude oil prices increased across the fourth quarter and averaged about $25.50 in December, with similar market backwardation as in late 1995. Demand and refinery production remained high. Crude oil inventories finished 1996 at historical lows, and major light

Figure 4-2. Inventories vs. Forward Market.



Source of Data: NYMEX and Energy Information Administration.

petroleum product inventory levels were comparable to year-end 1995.

THE PERIOD OF INVENTORY BUILD: THE PHASE FROM EARLY 1997 THROUGH MID-1998

A second phase of the 1995–98 inventory cycle began in early 1997. This period experienced increasing inventories and falling prices. In December 1996, Iraqi oil production, which was restricted to about 550 thousand barrels per day (MB/D) since about 1993, increased to about 900 MB/D and by May 1997 was over 1,300 MB/D. The increased crude oil availability from Iraq plus production increases above quotas by other OPEC producers resulted in a decline in prices from the $25-per-barrel level at the end of 1996 to around $20 per barrel for most of 1997. The drop in prices for current delivery resulted in a contango market in early 1997 and inventories began to build. While Iraqi production varied from month to month, 1997 averaged about 1,200 MB/D, twice the production level in 1996. In November, OPEC increased their production quotas, essentially validating the current output reality.

In addition to increased supply, lower than anticipated demand occurred as a result of the economic collapse that swept Asia, beginning with the currency devaluation in Thailand in July 1997. Growth in petroleum consumption in the region, which had been expected to range between 600 and 800 MB/D in 1998, became negligible. In addition, the 1997–98 winter was one of the warmest on record in the Northern Hemisphere.

By the end of 1997, it was readily apparent that the market had a significant amount of excess supply, and current market prices fell from $25 per barrel at the end of 1997 to under $14 per barrel by June 1998. The falling market increased the contango and inventories increased rapidly, approaching the maximum of their operating range by mid-1998.

SUMMARY

From 1995 through 1998, inventories adjusted in a manner consistent with market incentives. The inventory movements from norms to apparent system limits had not previously been observed over so short a period of time. This period contained compressed and amplified manifestations of historical inventory movements. Retrospectively, the 1995–96 period was an event-induced downward inventory movement. In 1997, there was a transition to an accumulation phase caused by events that reversed the supply/demand imbalance.

CHAPTER FIVE

ABILITY TO RESPOND TO FUTURE DYNAMIC CONDITIONS

In order to address industry's future ability to respond to dynamic conditions, projections were made through the 2002 study period of major light petroleum product demand, U.S. refining capacity, and import availability. Two future supply/demand cases were developed—a base case and a high-demand case.

The details of the analysis on which this chapter is based are presented in Appendix C. This appendix includes the following:

- Demand projections
- U.S. refinery PADD capacity projections and tables
- Import availability projections
- Supply/demand balances
- Refinery utilization
- Refinery facility sale price summary.

CONCLUSIONS AND OBSERVATIONS

The NPC concludes that over the time period of this study, the petroleum supply system balancing mechanisms available to respond to product market events will not appreciably change. Therefore, the frequency or magnitude of significant (non-crude oil related) upward retail price moves are not likely to increase. This conclusion is predicated on the assumption that no additional regulatory constraints to capacity growth, operational flexibility, or import availability will be implemented.

The conclusion is based on the examination of two petroleum product supply/demand cases and the market mechanisms available to satisfy seasonal demands. In both cases, the same domestic refining distillation and conversion capacity growth was used, based on historical patterns of incremental growth at existing refineries offset by closures of smaller non-economic facilities. The base case demand projection is similar to the product demand growth observed over the last ten years and reflects the impact of cyclical economic activity on overall product demand. The high case assumes product demand growth rates observed over the last five years. This case was designed to test system capability against demand growths reflecting a period of relatively low petroleum product prices and continued economic expansion.

In the base case, demand and domestic refinery capacity growth are about equal, and no appreciable change in refinery operation, inventory behavior, or import patterns is required to satisfy demands. The high case demands are met through a small increase in domestic refinery distillation capacity utilization, optimization of some refinery yield flexibility, and an increase in gasoline imports. Inventory behavior and refinery capacity are unchanged. The resultant imports are well within expected Atlantic Basin import supply capabilities, and yield flexibility remains available to respond to unexpected events.

While the analysis assumes specific actions to respond to increased demands, multiple variables impact the marketplace, with U.S. refining capacity utilization and import availability only part of the equation. In reality, each company will independently evaluate and respond to supply, demand, and market conditions, based on its own assets, strategies, and capabilities. The result is the aggregate effect of these individual actions.

The focus on distillation capacity utilization as a measure of the ability of the domestic refining industry to respond to changes in the light product supply/demand balance is somewhat misleading. Distillation capacity is the least expensive to debottleneck, and the capacity in place in the United States is primarily determined by the need to keep downstream conversion facilities such as fluid catalytic crackers[1] and cokers[2] operating at capacity. It is primarily the yield flexibility in these conversion units that allows the industry to respond to market signals. As the demand for major light petroleum products has increased, the capacity of conversion units has increased at a much faster rate than the capacity of distillation units. The increased feedstocks required for these conversion units have been provided through a combination of small incremental distillation capacity increases, an increase in the utilization of existing facilities, and the import of feedstocks. While a significant portion of the spare distillation capacity has been utilized, distillation capacity will expand or imported feedstocks will be obtained, as needed, to keep these key conversion facilities fully utilized.

DEVELOPMENT OF U.S. MAJOR LIGHT PETROLEUM PRODUCT DEMAND CASES

The study evaluates a number of publicly available forecasts of major light petroleum product demand to develop a starting point for the study analysis. Since the forecasts were issued between August 1997 and January 1998, a downward adjustment to demand growth was made to account for recent changes in the global economic situation. This adjusted growth rate of 1.4 percent per year from 1997 through 2002 is similar to the compound average growth rate observed over the 1987–97 period.

The high-demand case is set at a level consistent with the higher demand growth observed over the 1992–97 period (2.1 percent per year). In 2002, the high case results in a major light petroleum product demand about 500 thousand barrels per day (MB/D) higher than the base case (Figure 5-1).

DEVELOPMENT OF U.S. REFINERY CAPACITY PROJECTION

Review of Changes in Refining Production Capacity

The capacity projection assumes that the existing fuel quality regulations continue throughout the study period. Establishment of new fuel regulations could affect these projections significantly. Estimates of changes in U.S. refining capacity from 1998 to 2002 were made by analyzing historical changes in U.S. refinery capacity from 1987 to 1997 and by reviewing past and current announcements of refinery unit construction activity. The capacity changes developed assume that the profitability of the refining industry in the 1998–2002 period will be similar to that over the past few years, with any margin improvements being small.

From 1986 to 1988, U.S. refining capacity did not change significantly. Though distillation capacity fell from 1988 through 1993, by the end of 1997 it was at essentially the same

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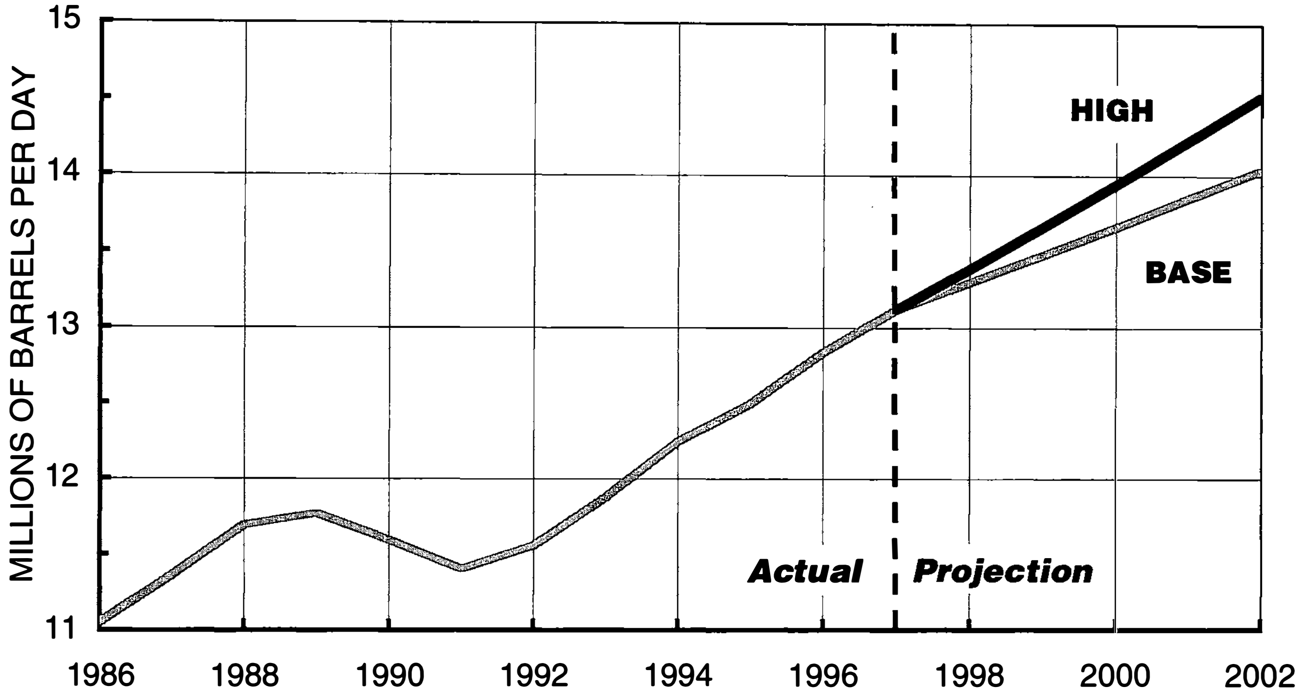
[1] Catalytic cracking is the refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil.

[2] Coking is a process by which heavier crude oil fractions can be thermally decomposed under conditions of elevated temperatures and pressure to produce a mixture of lighter oils and petroleum coke. The light oils can be processed further in other refinery units to meet product specifications. The coke can be used either as a fuel or in other applications such as manufacturing of steel or aluminum.

Figure 5-1. U.S. Total Major Light Petroleum Product Demand Projections.



Source of Data: Energy Information Administration/National Petroleum Council Projection.

level as in 1986. Utilization of distillation capacity increased steadily from 1981 to 1997. The concept of "maximum capacity" or 100 percent utilization is misleading and implies a finite limit. In fact, operational technology and operating flexibility can result in throughput rates above the refinery nameplate capacity. Based on market conditions, refiners can change crude oil inputs, product outputs, or other operational variables, sometimes exceeding nameplate capacity for extended periods. Although the distillation capacity has changed very little in the past decade, when refineries are analyzed based on size, location, and type of ownership, important differences emerge that provide a basis for projecting capacity changes for 1998 to 2002.

The capacity changes observed since 1987 are the net result of projects that expanded distillation and downstream unit capacities, but were offset by the elimination of process units and entire refineries. More than 60 refineries closed from 1987 through 1997. Most of these were smaller refineries of low complexity, many with little capability to convert the heavy portion of crude oil to light products, or to meet new regulations on product quality. Thus, the impact of the closures affected distillation capacity more than major light petroleum product production capability. As Table 5-1 shows, the closed refineries were almost exclusively small but in total equal over one million barrels of capacity.

A second major segment of distillation capacity reductions occurred at five very large multi-train refineries. Table 5-2 shows distillation capacity at Chevron's three largest refineries as of January 1, 1987 (El Segundo, Richmond, and Port Arthur, which is now owned by Clark), and Exxon's two largest refineries (Baton Rouge and Baytown). At the beginning of 1987, these five refineries totaled 2,110 MB/D of distillation capacity. By 1993, the total distillation capacity had dropped 643 MB/D to 1,467 MB/D. These very large refineries were reconfigured to be more efficient and, in some cases, to run heavier crude oils. Only in the case of Port Arthur were any downstream units eliminated. Since 1993, capacity has slowly increased at these refineries.

The amount of refinery capacity reduction has varied year to year, with no clear upward or downward trend. The number of closures per

TABLE 5-1

U.S. REFINERY CLOSURES 1987 TO 1997

Size Category	Number Closed	Capacity Closed (MB/D)
0–20 MB/D	47	378
20–40 MB/D	9	251
40–70 MB/D	6	291
> 70 MB/D	2	201
Total	**64**	**1,120**

year has decreased, but the average refinery size of the closures has increased. This study analyzes refinery closure at the PADD level. When the estimates for the individual PADDs are aggregated, the total annual closure rate for the 1998–2002 period is estimated to be 73 MB/D per year. This is about two-thirds of the rate between 1987 and 1997 and is lower because there are fewer candidates for closure. Some of the high historical closure years were when refineries were adapting to produce reformulated fuels. A key premise of this analysis is that no significant new product specification will occur in the 1998–2002 time frame. Thus, a modestly lower closure rate is projected.

Capacity increases also show different patterns based on types of refineries. In analyzing refinery capacity changes, refineries are grouped on the following bases for each PADD:

- Refinery size (small < 70 MB/D, large > 70 MB/D, and very large > 350 MB/D)
- Ownership (independents, foreign producing government interest).

As an example of the variation in capacity expansion by refinery category, the growth rate of PADD III refineries is shown in Table 5-3. Independents show the greatest expansion in distillation capacity. Refiners with foreign producing government ownership have no growth

TABLE 5-2

DISTILLATION CAPACITY REDUCTIONS AT LARGE MULTI-TRAIN EXXON AND CHEVRON REFINERIES* (Thousands of Barrels per Day)

		1987	1993	1997	Volume Change 1987–93	Volume Change 1993–97
Exxon Co. USA	Baton Rouge	455	421	432	-34	+12
Exxon Co. USA	Baytown	493	396	411	-97	+15
Large Multi-Train Exxon Refineries		948	817	843	-131	+26
Chevron USA Inc.	El Segundo	405	244	258	-161	+14
Chevron USA Inc.	Richmond	350	229	225	-121	+4
Clark (Chevron)	Port Arthur	407	177	204	-230	+27
Large Multi-Train Chevron Refineries		1,162	650	687	-512	+37
Total Exxon and Chevron		**2,110**	**1,467**	**1,530**	**-643**	**+63**

*Totals may not add due to independent rounding.

Source of Data: Energy Information Administration.

TABLE 5-3

PADD III ANNUAL PERCENT CAPACITY GROWTH—1987 TO 1997

Refinery Type	Number	Distillation	FCC	Coking
Independents	8	2.10	1.06	0.79
Producing Governments	7	-0.07	-0.08	7.75
Very Large Refineries	4	-1.69	1.06	3.05
Large Refineries	11	1.48	1.89	2.49
Small Refineries	25	1.05	1.32	-1.40
Weighed Average		0.43	1.09	3.97

Source of Data: Energy Information Administration Petroleum Supply Annual, DOE/EIA-0340, various issues.

in distillation or fluid catalytic cracking (FCC) capacity, but very high growth in coking capacity, consistent with greater use of heavy crude oils. The large refineries show growth in both distillation and downstream capacity, and the small refineries also show some growth in distillation capacity.

In the 1987–97 period, while distillation capacity increased only 66 MB/D, FCC capacity increased 366 MB/D and coking capacity increased 449 MB/D.[3] Analysis of refinery operating data in 1997 indicates that there is still enough distillation capacity to operate conversion units (such as FCC units and cokers) at very high utilizations.[4] In the future, expansion of FCC and coking capacity is expected to continue, and it is assumed that refiners will increase distillation capacity and/or import feedstocks necessary to run FCC and coking units at full utilization levels.

Refinery Margin Environment

Refinery margins from 1987 through 1997 were volatile and, on average, well below those required for widespread new unit construction. The financial performance of refining is also reflected in the sales prices of refining assets. Analysis of 15 refinery sales from 1991 to 1998 shows that refinery sales were in the range of \$700–\$2,900/daily barrel. These were often refineries with capacity in a very competitive size range and with recent investments to meet environmental requirements. Estimated replacement cost for a new 200 MB/D conversion refinery in the United States is more than \$10,000/daily barrel, which means that sale prices are less than 30 percent of replacement costs. As a result, the majority of capacity changes have been incremental expansions of existing units. Unit expansions are possible with debottlenecking projects and through application of process technology improvements. Process technology improvements are expected to continue through the 1998–2002 period, making it possible to continue capacity expansion and maintain yield flexibility on existing units.

The NPC does not believe that margins will increase sufficiently to induce construction of new grass roots refineries. There will likely continue to be incremental expansion of units and closure of small marginal refiners. Distillation capacity is expected to increase at a slightly faster than historical rate to keep up with conversion capacity increases. A high-demand scenario might produce some additional small

[3] EIA collects FCC and coking data on a stream day basis; the barrels-per-day basis has been estimated by using stream day factors of .95 for FCC and .92 for cokers.

[4] Energy Information Administration, *Assessment of Summer 1997 Motor Gasoline Price Increase*, DOE/EIA-0621, May 1998.

margin improvements over the base case, which could result in additional capacity growth. However, the base and high-demand cases utilized the same U.S. refinery capacity projection.

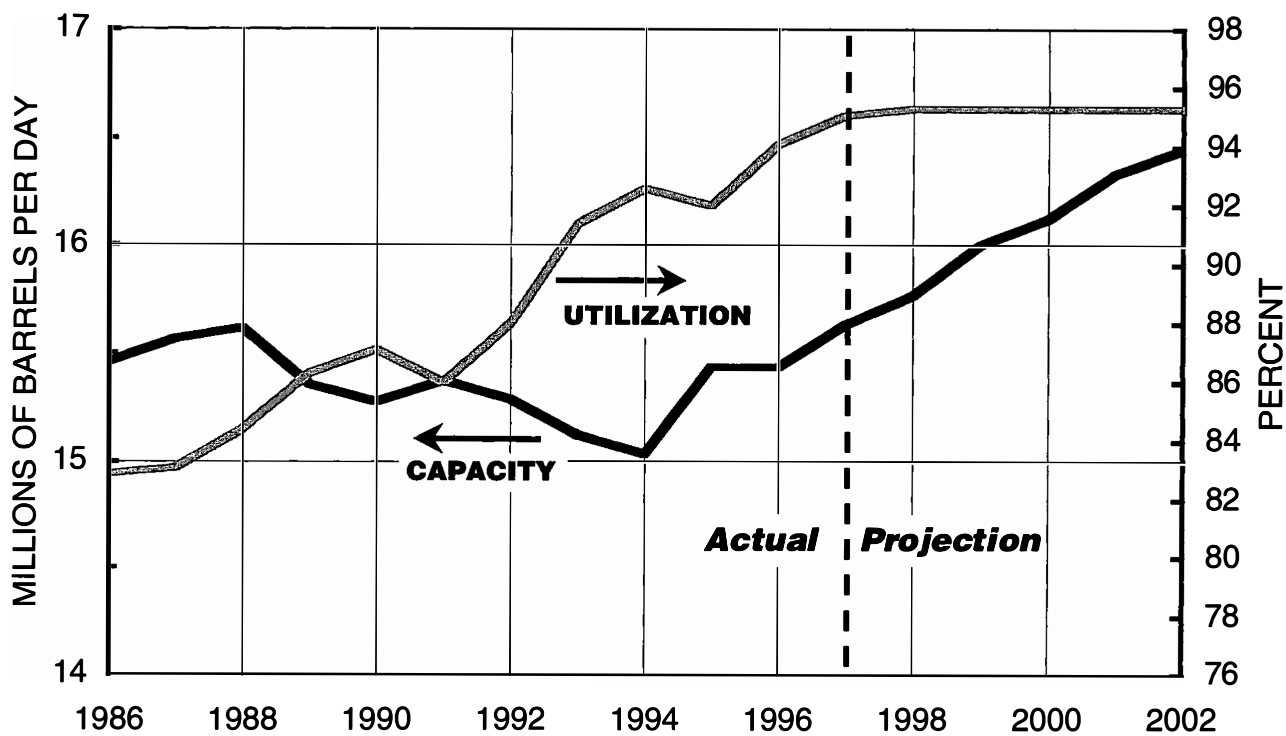
Projection of U.S. Refinery Capacity Changes 1998–2002

This study analyzes historical U.S. refinery capacity for the 1987–97 period, and projects refinery capacity changes through the year 2002. The analysis and projection considered changes for atmospheric distillation capacity and for two key refinery conversion processes, fluid catalytic cracking and coking. The historical and projected atmospheric distillation capacity and capacity utilization are shown in Figure 5-2, and FCC and coking capacity are shown in Figure 5-3. Historically, distillation capacity and the two key conversion processes show sharply different trends. The conversion capacity either rose or stayed flat, but the distillation capacity fell significantly from 1988 to 1994.

Table 5-4 details the net capacity projections developed in this study. From 1997 through 2002, distillation capacity is estimated to increase by 813 MB/D (5 percent), FCC capacity by 431 MB/D (8 percent), and coking by 305 MB/D (14 percent).

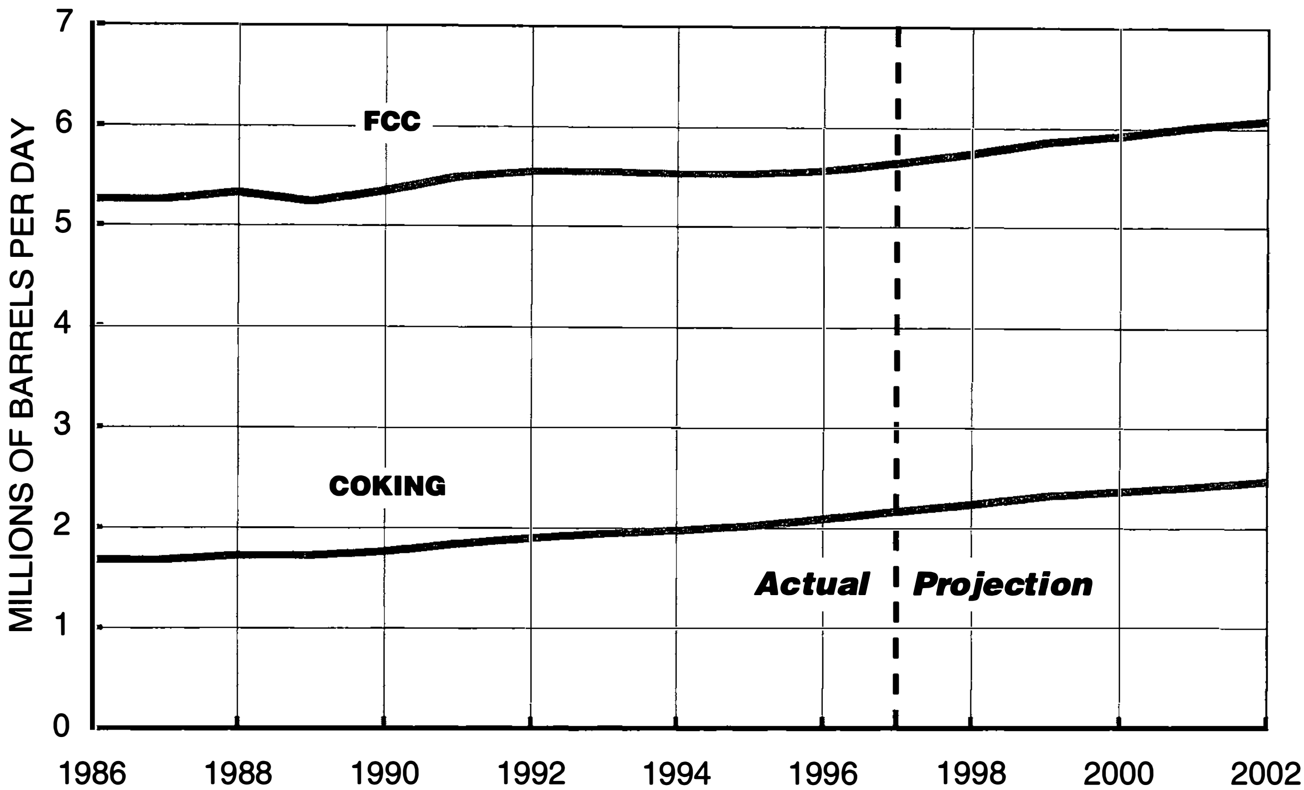
The estimates of capacity change for the 1998–2002 period are developed by PADD (in some cases, by refining areas within the PADD) for specific refinery groups as defined by size and ownership. In addition to relying on analysis of historical capacity data, unit construction reports for the historical period and for the early years of the projection period are analyzed. The historical period shows unreported capacity expansion (creep capacity), which is expected to continue and was factored into the results shown in Table 5-4. The projection also accounts for a continuing loss of capacity because of refinery closures. However, capacity reductions similar to those which occurred at the very large Chevron and Exxon refineries are not expected to recur. This assumption creates a different pattern for distillation capacity growth than occurred historically. Detailed

Figure 5-2. U.S. Refinery Distillation Capacity and Utilization.



Source of Data: Energy Information Administration/National Petroleum Council Projection.

Figure 5-3. U.S. Refinery Conversion Capacity.



Source of Data: Energy Information Administration/National Petroleum Council Projection.

TABLE 5-4

U.S. REFINERY CAPACITY PROJECTION: CAPACITY GROWTH SUMMARY

	1987	1993	1997	2002
Atmospheric Distillation (MB/D)	15,566	15,121	15,632	16,445
Fluid Catalytic Cracking (MB/D)	5,261	5,548	5,646	6,077
Coking (MB/D)	1,675	1,936	2,163	2,468

	Annual Growth Rate(%) 1987-97	Volume Change (MB/D) 1987-97	Annual Growth Rate(%) 1993-97	Volume Change (MB/D) 1993-97	Annual Growth Rate(%) 1997-2002	Volume Change (MB/D) 1997-2002
Atmospheric Distillation	0.0	66	0.8	511	1.0	813
Fluid Catalytic Cracking	0.7	385	0.4	98	1.5	431
Coking	2.6	488	2.9	325	2.7	305

Source of Data: Energy Information Administration/National Petroleum Council projections.

documentation of the PADD-level projections is given in Appendix C.

DEVELOPMENT OF MAJOR LIGHT PETROLEUM PRODUCT IMPORT AVAILABILITY

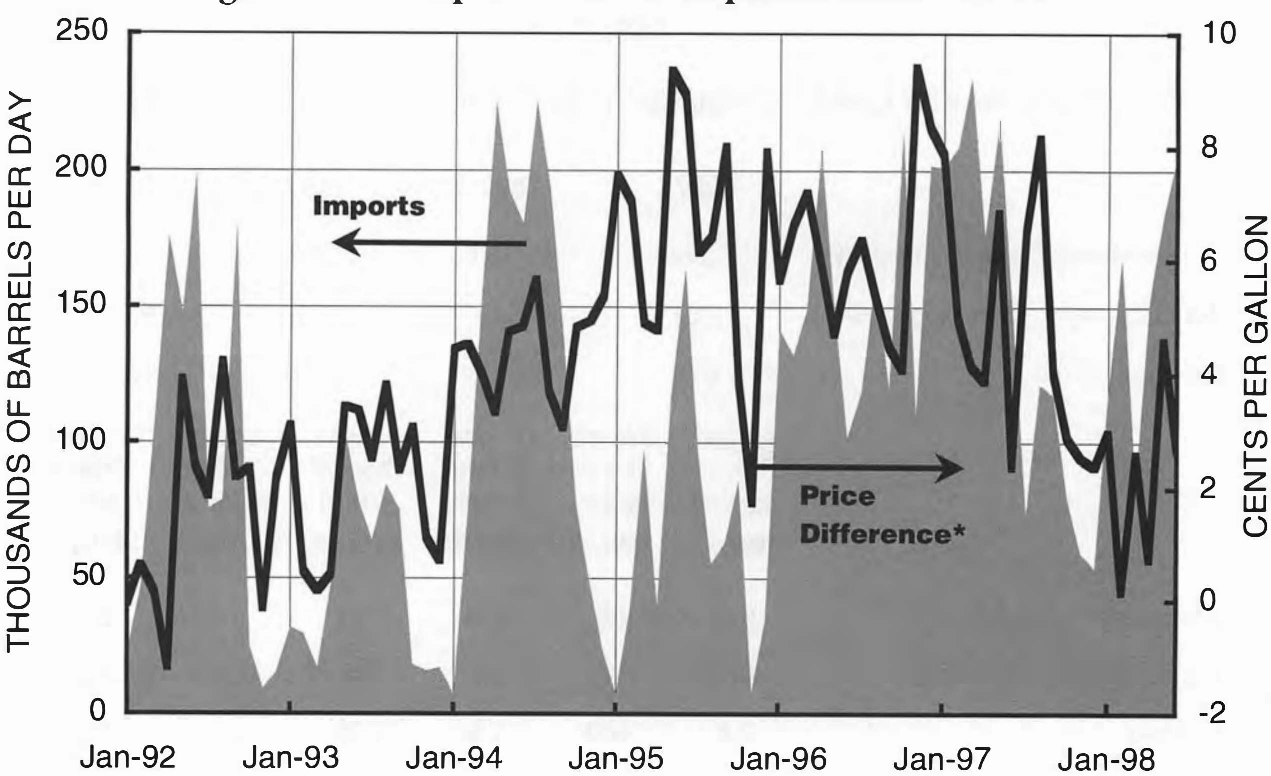
This study reviews the historical pattern of product imports into the United States and, in particular, into PADD I (East Coast). Europe tends to be a major source of marginal imports. A comparison of monthly European gasoline import data in conjunction with the difference between prices on the U.S. East Coast and those in Europe show that a rise in the price incentive to move product from Europe to the United States normally brings an increase in the volume of imports (Figure 5-4). The price incentive must exist in forward markets to mitigate the price risk associated with the transit time.

Global major light petroleum product trade patterns in recent years are expected to remain relatively unchanged through 2002. British Petroleum has forecast continued surplus gasoline production capability in the Eastern Atlantic Basin through 2002.[5] In Europe, the key trend is growth in diesel demand and very limited gasoline demand growth. As additional diesel is produced to meet demand, coproduction of gasoline will also occur and be available to the U.S. market. While Europe exports gasoline to a variety of markets, the United States will likely still provide the most attractive opportunity (see Table 5-5).

The U.S. East Coast continues to be a key market for opportunistic sellers of major light petroleum products. As discussed in Chapter One, Canada, Venezuela, and the Virgin Islands are the major suppliers of major light petroleum products to the United States, averaging over 580 MB/D over the 1993–97 period. There is every indication that these countries will continue to supply the United States with increasing levels in the future. In addition, these countries have demonstrated the capacity

[5] The British Petroleum Company p.l.c., Long Term Environmental Assumptions Document 1997.

Figure 5-4. European Gasoline Imports and Price Incentive.



**New York Harbor-Rotterdam Gasoline Price Difference*

Source of Data: Energy Information Administration.

TABLE 5-5

OECD EUROPEAN GASOLINE EXPORTS BY DESTINATION
(Thousands of Barrels per Day)

Exports to	1994	1995	1996	1997
United States	158	97	160	130
Africa	34	36	38	N/A
Latin America	9	16	18	N/A
Asia	5	4	3	N/A
Eastern Europe	40	47	58	N/A
Former Soviet Union	16	37	29	N/A
Middle East	16	21	17	N/A

Source of Data: International Energy Agency and American Petroleum Institute.

to increase their shipments as demand and price opportunities develop. These sources of supply are in a position to respond to export opportunities throughout the study period.

DEVELOPMENT OF SUPPLY/DEMAND BALANCES

Analytical Approach

This section describes the estimates of supply/demand balances for 1998–2002 and the projected changes in refinery capacity utilization and imports required to supply increased major light petroleum product demand. A monthly supply/demand balance analysis is required to determine when periods of high utilization, increased import requirements, or inventory reductions might occur. A simplified spreadsheet model (described in Appendix C) was developed to estimate the monthly supply and demand dynamics for the major light petroleum products for the 1998–2002 time period. The model uses the historical seasonal demand patterns for gasoline, distillate, and kerosene jet fuel. A monthly balance of refinery production is calculated, inventories are assumed to follow normal seasonal patterns, and imported products are used to balance supply. The primary factors taken into account include oxygenate to RFG blending, butane adjustments to meet gasoline specifications, and yield optimization of gasoline and distillates in refineries. The model assumes that all current and projected FCC and coking capacity is fully utilized and calculates product balances individually for gasoline, kerosene jet fuel, and distillate.

Supply/Demand Analysis: Base Case Results

The base case analysis uses demand and refinery capacity projections shown in Table 5-6 and described previously. In the base case, estimated distillation capacity increases at a little over 1 percent per year, a rate slightly less than the growth rate for gasoline demand. Due to the small change in the domestic supply/demand balance over the study period, gasoline imports alone are used to meet the incremental supply requirements. Refinery utilization rates in all of the years during the high throughput summer months are at about the same levels as the 1997 utilization. The annual net gasoline imports increase only about 60 MB/D. This is well within the Atlantic Basin's projected ability to provide gasoline to the United States. Alternatively, this increased demand could be met with a less than 0.5 percent yield increase of gasoline from the domestic refining system or a similar increase in refining capacity.

TABLE 5-6

BASE CASE SUPPLY/DEMAND BALANCES—1997 TO 2002

	Actual 1997	1998	1999	2000	2001	2002	Growth Rate
Annual Demands for Light Products (MB/D)							
Gasoline	8,017	8,112	8,209	8,307	8,406	8,506	1.19%
Distillate	3,435	3,481	3,528	3,575	3,623	3,671	1.34%
Kero Jet Fuel & Kerosene	1,664	1,702	1,741	1,781	1,822	1,864	2.30%
Total Light Product	13,116	13,295	13,478	13,663	13,851	14,041	1.37%
Distillation Capacity	15,632	15,705	16,002	16,124	16,333	16,445	1.25%
Supply/Demand Estimates: Annual Averages							
Distillation Capacity Utilization (%)	95.3	95.3	95.3	95.3	95.3	95.3	
Total Net Gasoline Imports (MB/D)	358	310	300	329	350	412	
Supply/Demand Estimates: May–Sept. Summer Season							
Distillation Capacity Utilization (%)	98.2	98.2	98.3	98.2	98.2	98.2	
Total Net Gasoline Imports (MB/D)	417	370	361	391	412	475	

Supply/Demand Analysis: High-Demand Case Results

The high-demand growth case is neither an expected nor likely case, but is examined to assess what operational changes might be required in a stress mode. In the high-demand case, U.S. major light petroleum product demand grows at a faster rate than projected refining capacity. This case is balanced by a combination of higher refinery utilization rates and increased gasoline imports. As shown in Table 5-7, from 1997 through 2002, annual distillation capacity utilization increases from 95.3 percent to 96.7 percent, with the high throughput summer months increasing from 98.2 percent to 99.4 percent. The greater increase for the annual capacity utilization versus the summer month utilization results from a significantly higher growth rate for distillate than for gasoline. While yield patterns, inventory patterns, and import patterns could all shift to accommodate the higher distillate growth rate, modest changes to yield patterns were used in the model to deal with the high distillate demand growth. In practice, additional yield flexibility, higher imports, or changed seasonal inventory patterns could reduce the utilization during the high throughput summer months.

Net gasoline imports increase from 358 MB/D to 512 MB/D annually and from 417 MB/D to 579 MB/D for the summer period from 1997 through 2002. These estimates for gasoline imports fall within expected availability and are equivalent to about a 1-percent increase in either domestic capacity or gasoline yield.

TABLE 5-7

HIGH-DEMAND CASE SUPPLY/DEMAND BALANCES—1997 TO 2002

	Actual 1997	1998	1999	2000	2001	2002	Growth Rate
Annual Demand for Light Products (MB/D)							
Gasoline	8,017	8,152	8,289	8,428	8,569	8,713	1.68%
Distillate	3,435	3,538	3,644	3,754	3,866	3,982	3.00%
Kero Jet Fuel & Kerosene	1,664	1,696	1,728	1,761	1,795	1,829	1.91%
Total Light Product	13,116	13,386	13,661	13,943	14,230	14,524	2.06%
Distillation Capacity	15,632	15,705	16,002	16,124	16,333	16,445	1.25%
Supply/Demand Estimates: Annual Averages							
Distillation Capacity Utilization (%)	95.3	95.4	95.6	95.8	96.1	96.7	
Total Net Gasoline Imports (MB/D)	358	351	375	429	474	512	
Supply/Demand Estimates: May–Sept. Summer Season							
Distillation Capacity Utilization (%)	98.2	98.2	98.5	98.7	99.0	99.4	
Total Net Gasoline Imports (MB/D)	417	413	439	494	540	579	

APPENDICES

Appendix A

Request Letter from the Secretary of Energy and Description of the National Petroleum Council

The Secretary of Energy
Washington, DC 20585

September 16, 1997

Mr. Joe B. Foster, Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

This letter is a follow-up to a January 17, 1997, letter from the Department of Energy (DOE) to the National Petroleum Council (NPC) and our meeting of April 14, 1997. Since then there have been several meetings between Department and NPC staff that have helped determine the focus of a study of petroleum product inventories that will meet DOE needs and is still within the resources of the NPC.

As you are aware, the tight supply conditions in the 1996 and early 1997 U.S. petroleum product market, which were accompanied by higher and more volatile prices, raised concerns in government and among consumers about the possible role of lower product inventories as a factor behind the tight market and the likelihood that future trends would bring about similar markets in the future. During 1996, DOE released a study commissioned by the President (the *45-Day Study*) that identified a number of contributing factors behind the spring 1996 price trends. This study concluded that the exceptionally low inventories of 1996 were probably an anomaly but also noted that there was a clear long-term trend towards lower inventories as measured in barrels of product or days of supply. For some products, these levels are below minimum operating levels identified in the 1989 NPC study on *Petroleum Storage and Transportation*. Minimum operating levels were defined as the inventories, below which, operating problems and shortages would begin to appear.

While the market handled the 1996 and early 1997 situations without experiencing supply problems (in part because of relatively warm winter weather), increased prices and price volatility were required to balance the supply. The Department believes that these developments raise analytic issues that could be effectively addressed by the NPC. Accordingly, I am requesting that the Council undertake a narrowly focused and timely study that addresses the following:

1a. What are the factors behind the long-term decline in product inventories and is this trend likely to continue over the next few years?

1b. Were the inventory levels of 1996 an anomaly or a steepening of this long-term decline?

2a. In the context of these long-term trends, are minimum operating levels (inventories) still a useful concept for the Department to use as a benchmark or indicator of possible future problems in supplies or prices?

2b. Can the NPC define such levels of inventories (either as minimum operating levels or some other construct) that, if not maintained, would cause supply problems and how do such levels compare to those identified in the 1989 study or the *minimum observed inventories* now used by the Energy Information Administration?

3. In the context of these apparently permanent lower inventory levels, will capacity limitations in the industry, coupled with demand growth (particularly for middle distillates) diminish the industry's ability to respond to dynamic conditions? Will larger price swings become a more frequent and necessary element of market balancing?

For the purposes of this study, Mr. Marc W. Chupka, Acting Assistant Secretary for Policy and International Affairs, will represent me in providing the necessary coordination between the Department of Energy and the Council.

As always, I appreciate the NPC's ongoing assistance in these issues of national policy and mutual concern.

Sincerely,

Federico Peña

Description of the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Enhanced Oil Recovery (1984)*
- *The Strategic Petroleum Reserve (1984)*
- *U.S. Petroleum Refining (1986)*
- *Factors Affecting U.S. Oil & Gas Outlook (1987)*
- *Integrating R&D Efforts (1988)*
- *Petroleum Storage & Transportation (1989)*
- *Industry Assistance to Government (1991)*
- *Short-Term Petroleum Outlook (1991)*
- *The Potential for Natural Gas in the United States (1992)*
- *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries (1993)*
- *The Oil Pollution Act of 1990—Issues and Solutions (1994)*
- *Marginal Wells (1994)*
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)*
- *Future Issues—A View of U.S. Oil & Natural Gas to 2020 (1995)*
- *Issues for Interagency Consideration—A Supplement to the NPC's Report: Future Issues (1996).*

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL

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APPENDIX B

STUDY GROUP ROSTERS

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APPENDIX C

APPROACH TO PROJECTING SUPPLY/DEMAND BALANCE AND REFINERY UTILIZATION

This appendix describes a spreadsheet model developed to calculate a U.S. supply/demand balance for major light petroleum products for future years. Each year is estimated separately by month. The model structure is based on a historical analysis of monthly patterns for demand, refinery production, inventory build/draw cycles, yield shift during the year, and use of product imports and other feedstocks. Background is first provided, then the logic of the model calculation approach is described, and finally the model's use is illustrated with results from the 1998–2002 base case analysis.

DEVELOPMENT OF U.S. MAJOR LIGHT PETROLEUM PRODUCT DEMAND

In order to assess the future ability of the refining system to respond to demand requirements, it is necessary to look at what those demand requirements may be. The study looked at a number of publicly available forecasts of major light petroleum product demand. Since the forecasts had been issued between August 1997 and January 1998, an adjustment was made to account for recent changes in the global economic situation in order to prepare a base case projection. This projection was then subjected to a review for reasonableness. The high demand case was set at a level consistent with the high demand growth of the 1992–97 period.

The base case projection of U.S. major light product demand through 2002 was developed from an assessment of forecasts by these recognized organizations: The Energy Information Administration's Annual Energy Outlook (AEO), Petroleum Industry Research Associates (PIRA), Data Resources Inc. (DRI), Gas Research Institute (GRI), and Petroleum Economics Ltd. (PEL). These forecasts are graphically represented in Figures C-1 to C-3. These industry forecasts were compared and an assessment performed. To arrive at the base case projection, an adjustment was made reducing the forecasts' average annual compound growth rate from 1.7 percent to a 1.4 percent growth rate. The rationale for that adjustment is described below.

The base case was subjected to reasonableness tests. This base case now is similar to the compound average growth rate over the 1987–97 period. Figures C-4 to C-7 reflect the base case

Figure C-1. U.S. Gasoline Demand Industry Forecast.

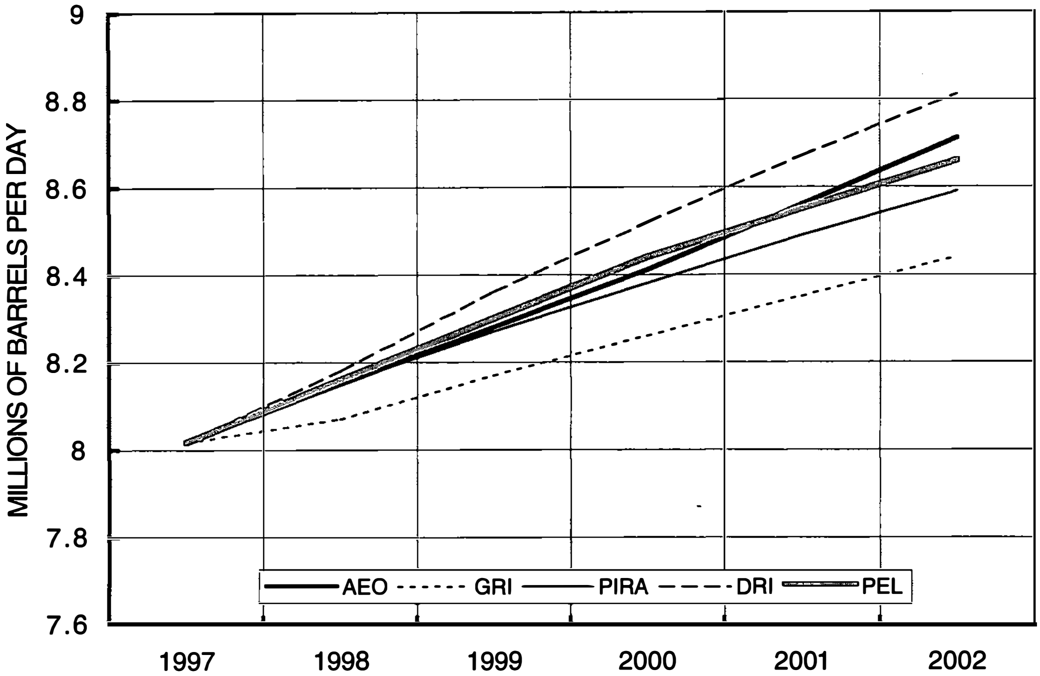


Figure C-2. U.S. Kerosene Jet Fuel, Kerosene, and Distillate Demand Industry Forecast.

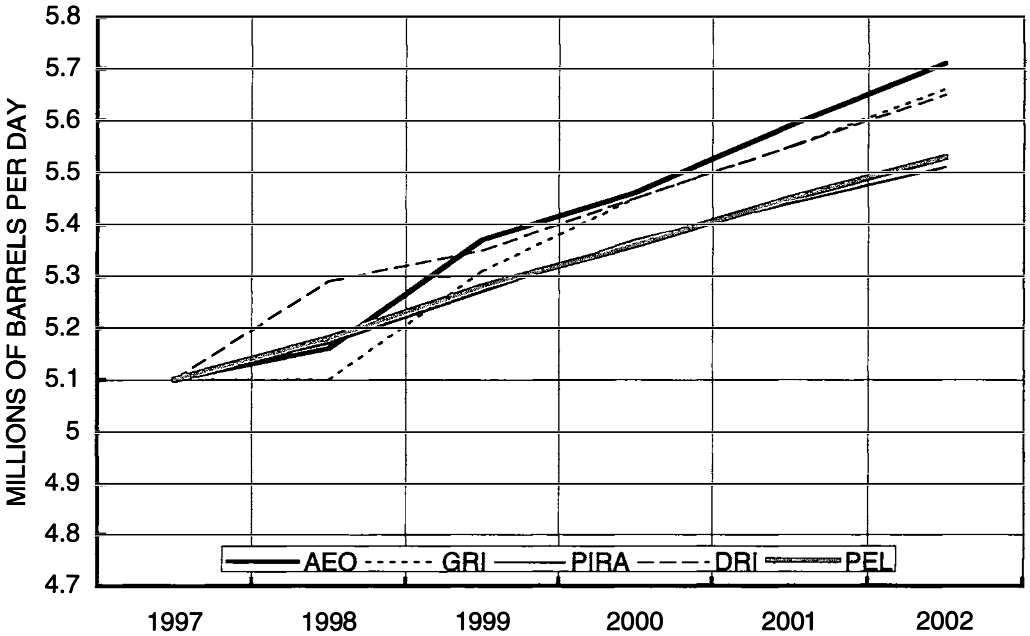


Figure C-3. U.S. Total Major Light Petroleum Product Demand Industry Forecast.

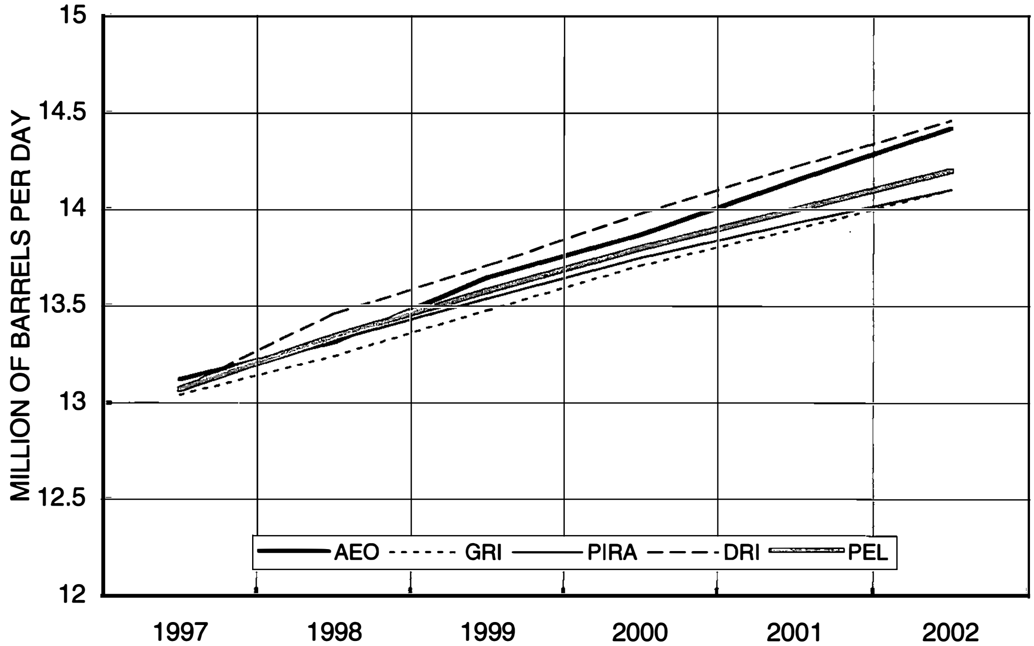


Figure C-4. U.S. Total Major Light Petroleum Product Demand Projections.

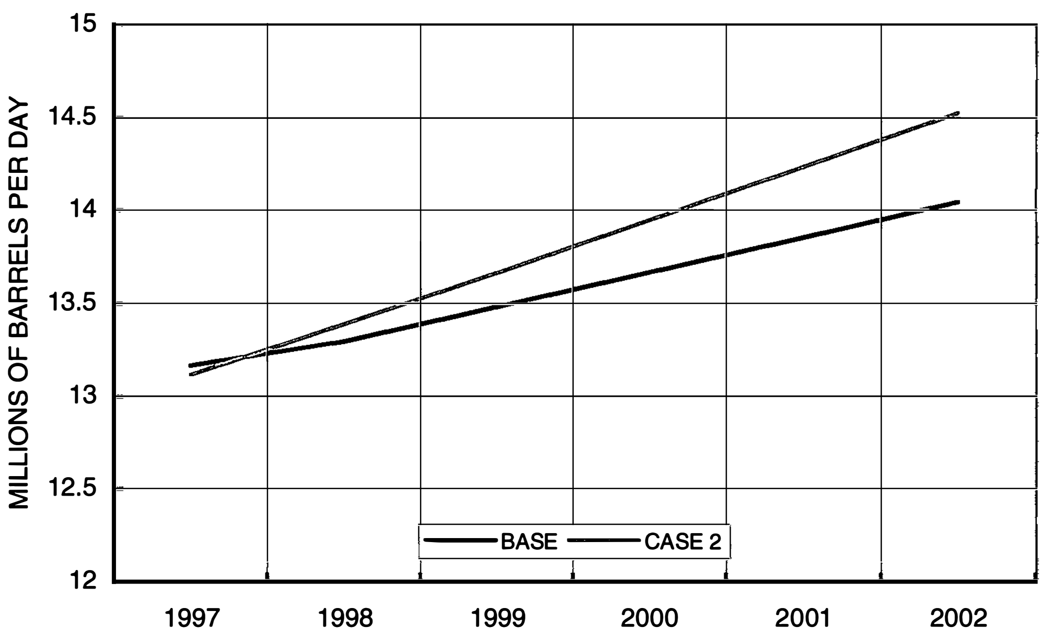


Figure C-5. U.S. Gasoline Demand Projections.

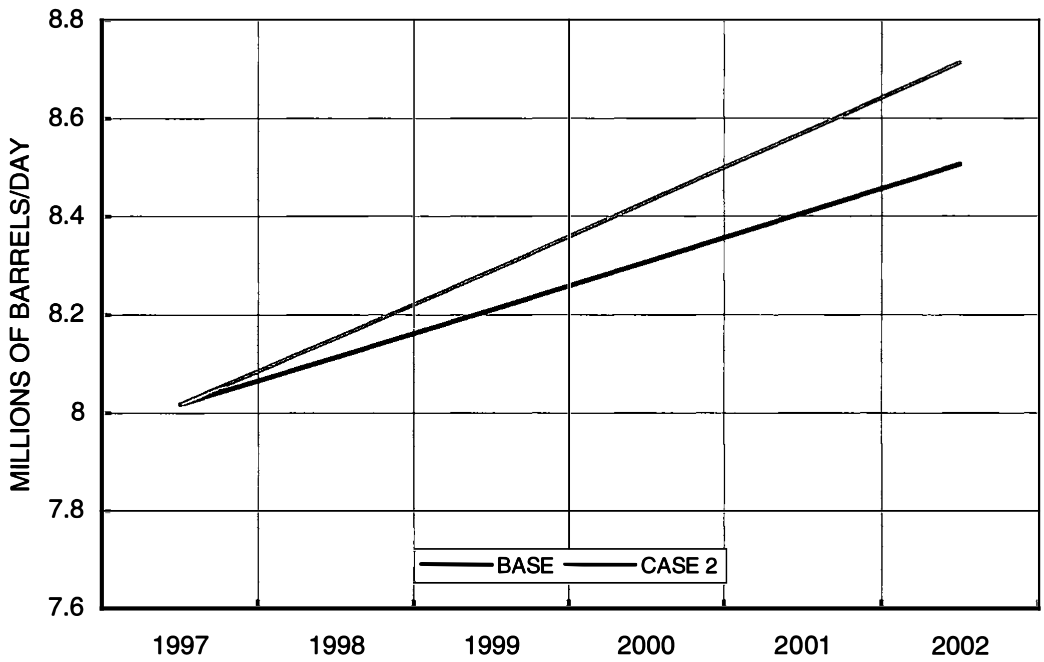


Figure C-6. U.S. Distillate Demand Projections.

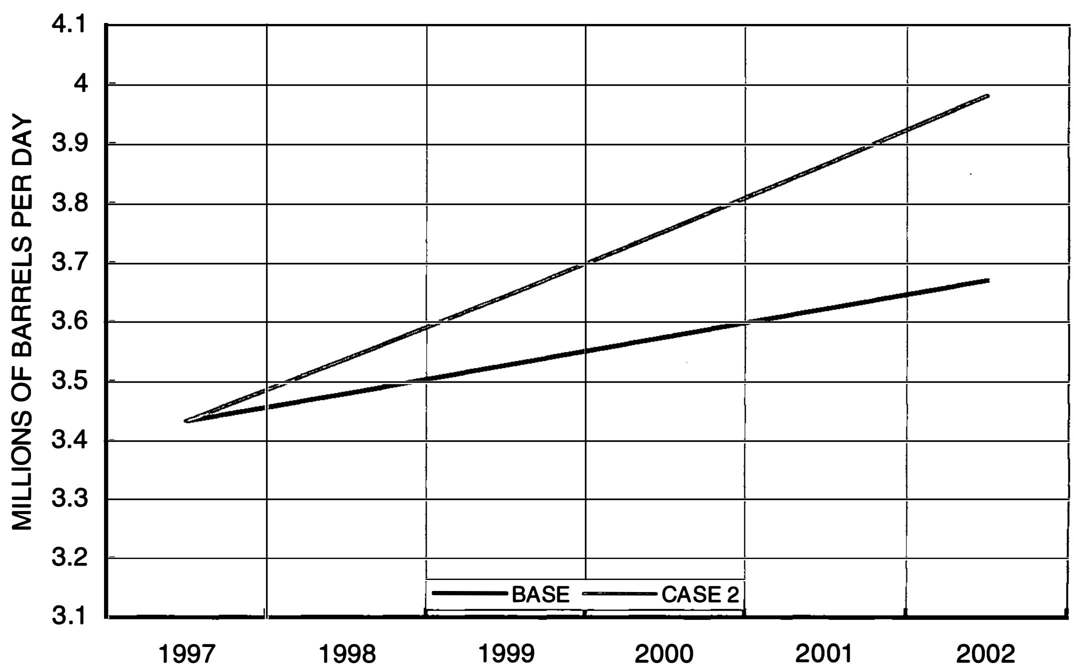
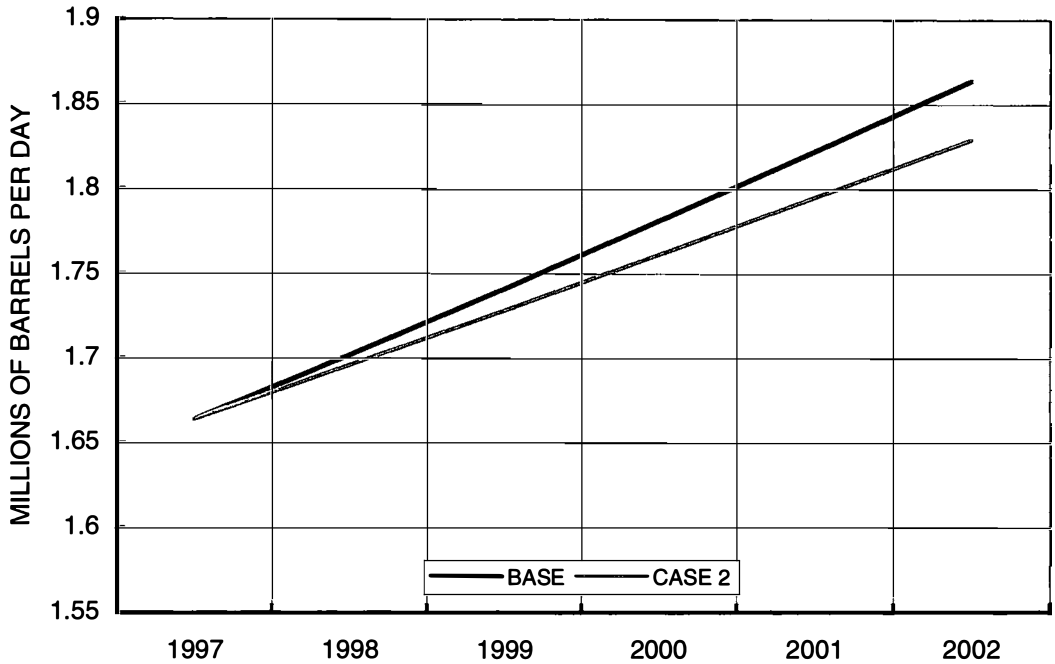


Figure C-7. U.S. Jet Fuel and Kerosene Demand Projections.



major light petroleum product demands. In addition to the Far East economic situation, there are a number of other reasons that the adjustment of the average of these forecasts is reasonable. The U.S. economy is now in its eighth year of economic expansion, exceeding all but one of the nine previous post-World War II economic expansions. The U.S. economy is expected to register continued growth through 2002. However, economic expansion is projected to slow from 3.0 percent in 1998 to between 2.0 and 2.5 percent per year. The base case demand is consistent with that lower level of economic activity.

A second factor is the price of oil. For purposes of this analysis, underlying crude oil costs are projected to be flat in real (inflation-adjusted) terms at their 1997 levels. These are above the prices currently being experienced in 1998. Even with the current low price environment, demand appears to be below that which would be expected based upon the 1992–97 annual growth rate. If prices return to the 1997 levels, further dampening of demand growth may occur.

PROJECTED U.S. MAJOR LIGHT PETROLEUM PRODUCT DEMAND

Table C-1 is a summary of the base case for the study. This is not an industry forecast, it is a projection that is used to determine outcomes. The base case lies at the low to mid-region of the published forecasts. This was utilized as a base case to show the industry's ability to respond to certain circumstances. The base case major light petroleum product demand reflects a compound average growth rate of 1.4 percent per year from 1997 through 2002.

TABLE C-1. NPC BASE CASE

	Annual Demand for Light Products (Thousand Barrels per Day)						Growth Rate (%)
	1997	1998	1999	2000	2001	2002	
Gasoline	8,017	8,112	8,209	8,307	8,406	8,506	1.2
Distillate	3,435	3,481	3,528	3,575	3,623	3,671	1.3
Kerosene & Kero Jet	1,664	1,702	1,741	1,781	1,822	1,864	2.3
Total Light Product	13,116	13,295	13,478	13,663	13,851	14,041	1.4

Gasoline demand is projected to grow by about 1.2 percent per year, from 8.02 MMB/D in 1997 to 8.51 MMB/D in 2002. Demand for middle distillates is projected to rise by about 1.3 percent per year, from 3.44 MMB/D in 1997 to 3.67 MMB/D in 2002. The gains in distillate are expected to be concentrated in the diesel component, rather than in heating oil. The continued favorable economic outlook will boost diesel usage in the on-road and railcar freight transport sector, and in the industrial use for diesel-powered off-road equipment, such as farm tractors and bulldozers. In contrast, higher-efficiency heating oil units and penetration by natural gas have slowed the growth in heating oil requirements from historical growth rates—a trend that is expected to continue in the years ahead.

Continued economic growth and rising incomes will also boost kerosene jet fuel (kero jet) demand, both for travel and shipping purposes. Over the next five years, kero jet demand is expected to grow by 2.3 percent per year, from 1.66 MMB/D in 1997 to 1.86 MMB/D in 2002.

The alternate projection is a higher case as shown in Table C-2. It is based on a continuation of the 1992–97 major light petroleum product demand growth rate of 2.1 percent

TABLE C-2. NPC DEMAND CASE #2 (1992–97 HISTORICAL GROWTH RATES)

	Annual Demand For Light Products (Thousand Barrels per Day)						Growth Rate (%)
	1997	1998	1999	2000	2001	2002	
Gasoline	8,017	8,152	8,289	8,428	8,569	8,713	1.7
Distillate	3,435	3,538	3,644	3,754	3,866	3,982	3.0
Kerosene & Kero Jet	1,664	1,696	1,728	1,761	1,795	1,829	1.9
Total Light Product	13,116	13,386	13,661	13,943	14,230	14,525	2.1

per year. In the alternate projection, gasoline consumption rises to 8.71 MMB/D and distillate consumption rises by 3 percent per year to 3.98 MMB/D. The kerosene and kero jet demand rises to 1.83 MMB/D. The kerosene and kero jet demand in Demand Case #2 is less than the base case due to the use of actual 1992–97 demand growth data for this case.

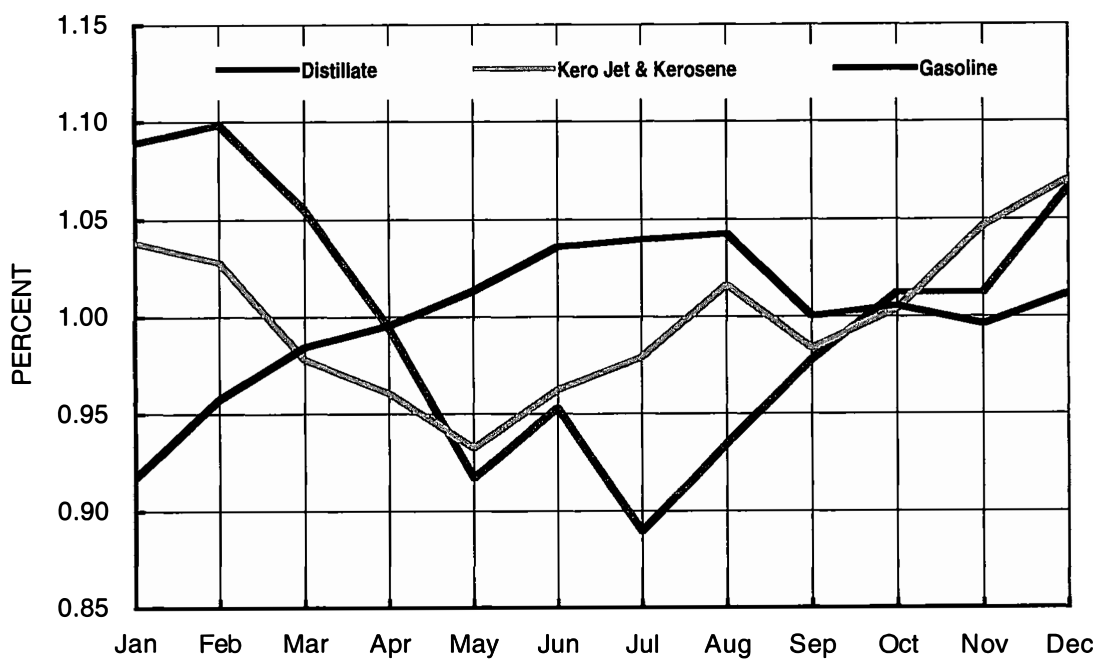
Since one of the purposes of the study is to look at the petroleum industry response to a stress situation, there is little benefit to generating a low demand case. The industry has shown the capability to meet demand at 1997 levels of consumption.

The projected supply of U.S.-manufactured major light petroleum products is based on an analysis of the U.S. refining system from 1987 to 1997. The analysis looked at announced capacity additions to crude oil distillation as well as downstream upgrading capacity. An additional factor is the "capacity creep," which is the increase in ability to process crude oil to products that occurs as part of the everyday optimization of an industry. The potential to operate at high levels of utilization is considered, as well as the ability to expand product or blendstock imports from other parts of the world.

DEVELOPING SUPPLY/DEMAND BALANCE ESTIMATES: BACKGROUND

The demand for gasoline, distillates (heating oil and diesel), and kerosene jet fuel have distinctive seasonal patterns that vary only slightly from year to year. The monthly demand divided by the year average demand for the light products are shown in Figure C-8. As shown, distillate is about 10 percent above the yearly average in the winter months of January and February and drops to 10 percent below (90 percent) by July. Kerosene/kerosene jet fuel is also higher in the winter and lower in the summer. By contrast, gasoline demand is lower in the winter months and higher in summer.

Figure C-8. Monthly Product Supplied as a Percent of Annual Average (Based on 1992–1997 Averages).



Source of Data: Energy Information Administration.

Refinery inputs and production levels are primarily geared to meeting gasoline demand, which is the highest volume light product. Thus, as Figure C-9 shows, gasoline production roughly follows the gasoline demand pattern, low in winter and rising in summer. Gasoline production is higher in the fall than would be expected from demand, but, as shown in Figure C-9, distillate production is highest in the fall to meet increasing demand and build inventories to meet winter peak demands. The high fall distillate production results in the co-production of gasoline in excess of monthly gasoline demand in the fall period. Because gasoline demand is the more dominant factor determining refinery input levels, monthly distillate production is more at variance with monthly demand. As shown in Figure C-10, in the cold winter months of January and February, 10 to 20 percent of distillate demand is typically met by drawing down distillate inventories, and, conversely, July production volumes generally exceed July demand by 10 percent and are added to distillate inventories.

The consequence of the seasonal product demand patterns is a cyclical pattern of higher summer and lower winter utilization rates as shown in Figure C-11. For the six-year period from 1992 to 1997, the average utilization rate for the four summer months (June through September) was 6.9 percent higher than for the winter months of January, February, and March. The important point of this discussion of the seasonal patterns of demand and refinery production that is incorporated in to the estimation approach for the 1998–2002 supply/demand forecast is that higher utilization levels may be reached in summer months than in winter when capacity utilization is 5 percent or more below the upper summer level.

When analyzing capacity utilization and estimating possible upper limits, it is important to review how the utilization rates are measured. DOE/EIA reports a refinery capacity utilization measure that is calculated by dividing the gross inputs to atmospheric crude oil distillation units by refinery operable calendar day distillation capacity. Calendar day capacity is an annual average capacity estimated by multiplying the stream day capacity (rated daily throughput capacity) by a stream day factor that accounts for the time off-stream for planned and unplanned outages. Thus on a calendar day basis, in some months capacity could be above 100 percent and in other months below 100 percent, if operating at upper levels. The 100 percent utilization level should not be interpreted as an absolute limit on refinery capacity. The more important consideration is the utilization of conversion units such as fluid catalytic cracking and coking used to make light petroleum products. Additionally, adjustments to refinery yield can be made by changes in crude oil quality or the purchase of feedstocks to meet the requirements of the conversion units.

The divisor in EIA's capacity calculation is operable capacity, which is the sum of operating and idle capacity, for which the capacity has zero throughput. Idle capacity, by its definition[1] might appear to be capacity that could come on stream when demand is high, but historically that has not been the case. In Figure C-12, which plots EIA's data for idle capacity, the much higher level for idle capacity in 1990–92 stems from the inclusion of 300 thousand barrels per calendar day capacity for the TransAmerican (Good Hope) Refinery, which never operated in the period. Refineries that have been in bankruptcy and have or have not returned to

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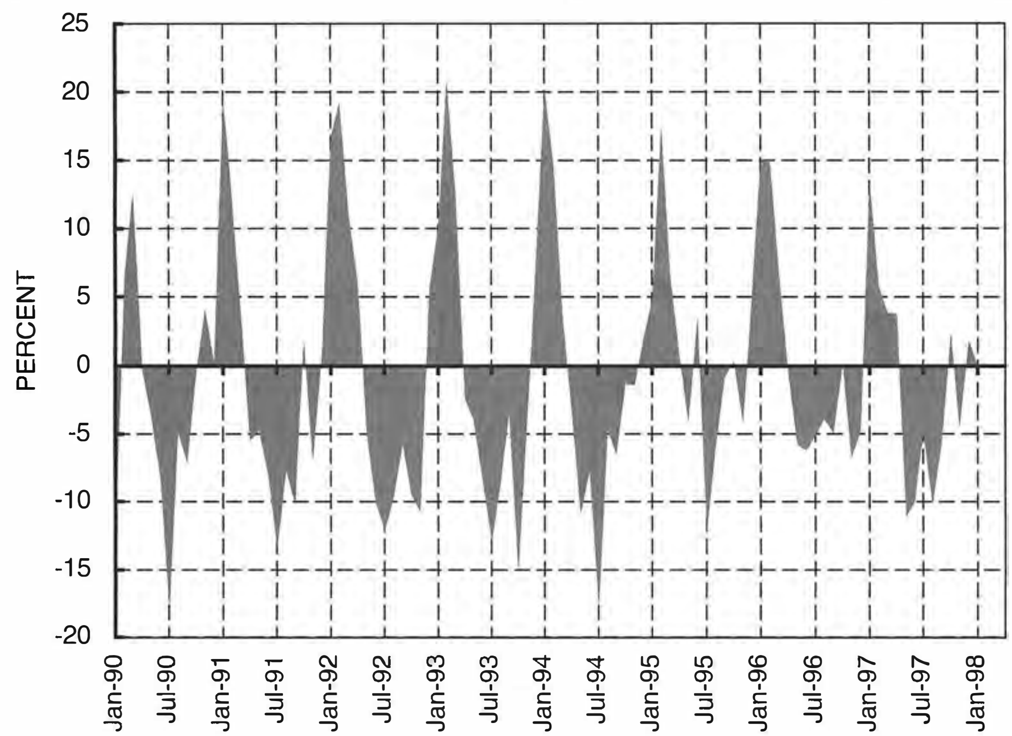
[1] Idle capacity is the component of operable capacity that is not in operation and not under active repair, but capable of being placed in operation within 30 days; and capacity not in operation but under active repair that can be completed within 90 days. DOE/EIA *Petroleum Supply Monthly.*

Figure C-9. Monthly Refinery Production as Percent of Annual Average (Based on 1992–1997 Averages).

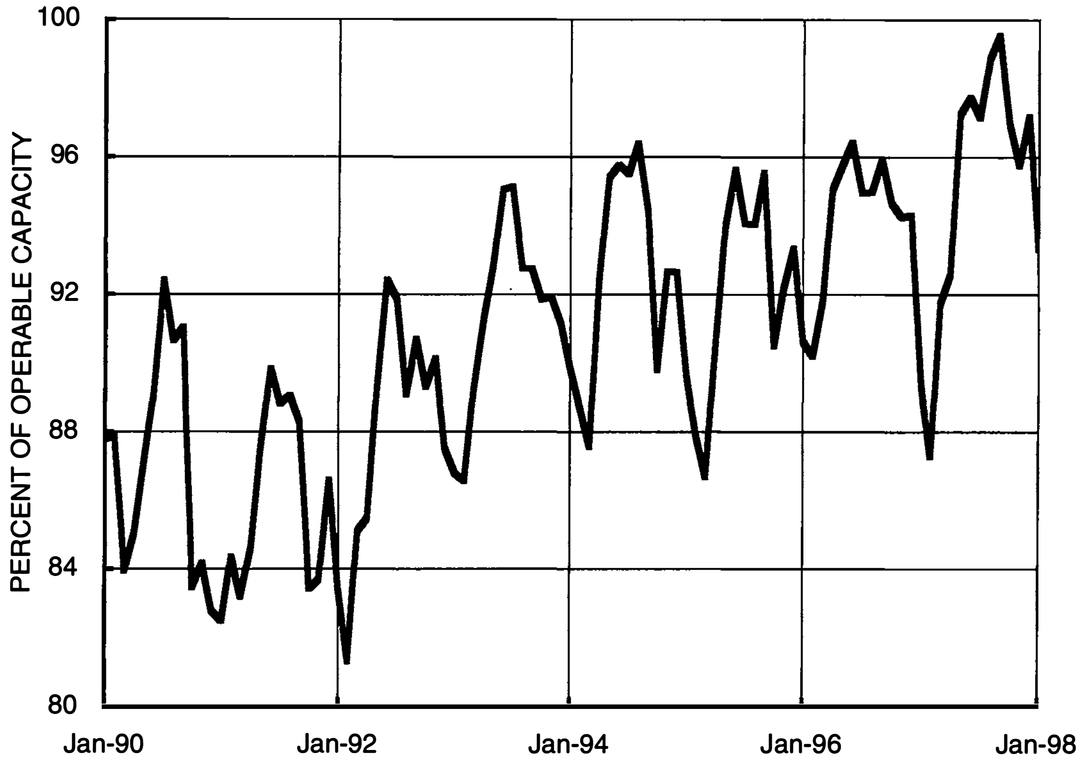
Source of Data: Energy Information Administration.

Figure C-10. Percent of Distillate Supplied from Inventory Change.



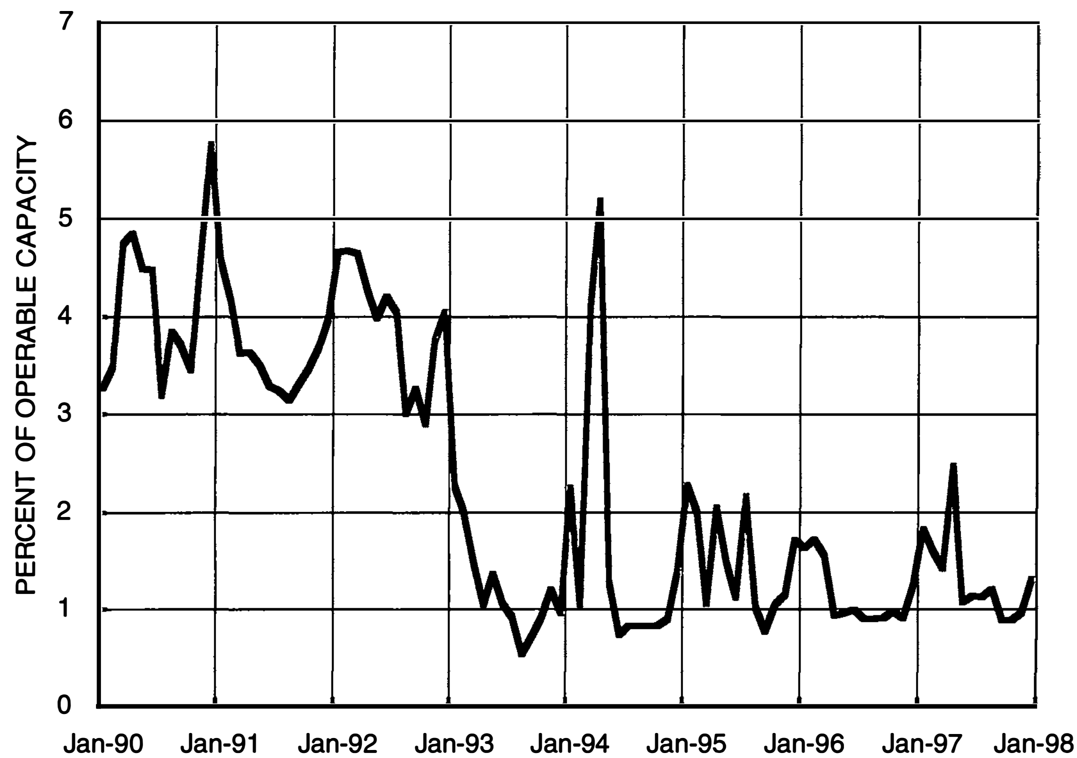
Source of Data: Energy Information Administration.

Figure C-11. Monthly Refinery Utilization.



Source of Data: Energy Information Administration.

Figure C-12. Idle Refinery Capacity as Percent of Operable Capacity.



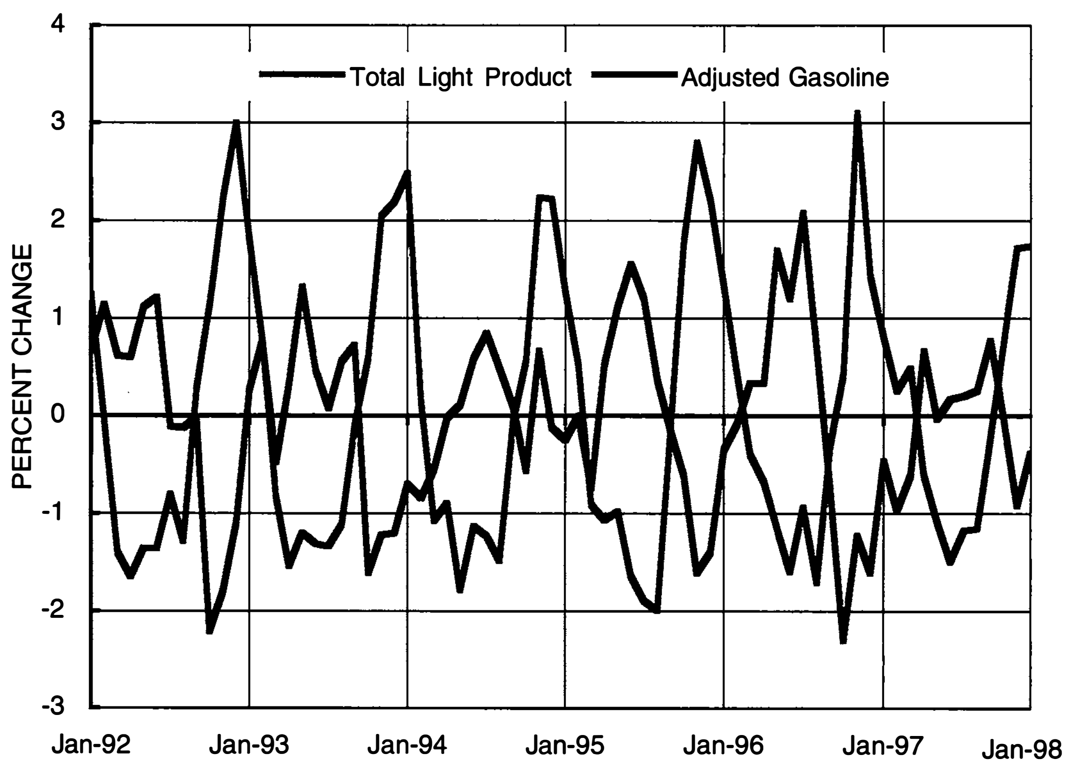
Source of Data: Energy Information Administration.

service, depending on resolution of financial problems, have been included along with capacity out of service from refinery accidents. Based on the data of the past few years, idle capacity runs about 1–2 percent of operable capacity.

Even among operating refineries, there are specialty refineries (e.g., asphalt refineries) and other refineries that operate at significantly lower utilization rates than most refineries. For the purposes of this supply/demand analysis, the upper operable capacity utilization level for the total U.S. for the summer period (May through September) after taking into account idle capacity, regional factors, and analysis of historical data on refinery operations,[2] is estimated at 100 percent. It could be higher, but 100 percent is used for the base case analysis. In the February–April time period, a lower estimate for utilization is used to account for high refinery maintenance activity in that time frame.

In addition to dealing with the seasonal pattern for light product yields and refinery production, higher demand growth for kerosene jet fuel and distillate versus gasoline and higher import availability of gasoline vs. distillate may require an increase in average yields of distillate vs. gasoline in future years. Analysis of refinery yield data has shown that as gasoline yield decreases total light product yields increase, i.e., the gain in distillate yield exceeds the decline in gasoline yield (Figure C-13). This relationship is represented in the supply/demand balance calculations.

Figure C-13. Monthly Yield of Light Products as Percent of Annual Average.



Source of Data: Energy Information Administration.

[2] A recent EIA report analyzed capacity utilization in high demand months of 1997, *Assessment of Summer 1997 Motor Gasoline Price Increase*, DOE/EIA-0621, May 1998.

SUPPLY/DEMAND ESTIMATION: ANALYTICAL APPROACH

The supply/demand analysis for the 1998–2002 period is performed using a spreadsheet model. Each year is calculated separately in the model. The historical patterns discussed in the previous section are used to do the analysis on a monthly basis. Annual demand is converted based on seasonal patterns.

- Monthly refinery inputs are a function of monthly demand levels and a factor to set the balance between refinery production and imports.
- Inputs of unfinished oil are assumed to be constant throughout the analysis period.
- Oxygenate input is a function of RFG production.
- Butane input to gasoline has a seasonal pattern as a monthly percentage of gasoline production.
- Monthly yield adjustment factors allow gasoline and distillate yields to vary within historical limits.

The model includes three product balances for distillate, kerosene jet fuel, and gasoline:

- Production changes with refinery input levels. The split of light product between distillate, kero jet, and gasoline can also be changed.
- Average kero jet yield is set for each year, gasoline yield can be altered by monthly yield adjustments, and distillate is simply total light product minus kero jet plus gasoline. In reality, some flexibility exists to change cut points, shifting yield between gasoline, kero jet, and distillate.
- Monthly net imports, based on historical monthly patterns are fixed for each year for kero jet and distillate and inventory changes are used as the balance item in monthly balances for these two products.
- For the gasoline balance, monthly inventory change volumes based on historical pattern are fixed and imports are the balance item. In reality, there is capacity to alter these storage patterns; gasoline could be seasonally stockpiled given sufficient economic incentive (contango).

For a forecast analysis, an objective is chosen such as estimating the impact of changes in demand and capacity on utilization rates or gasoline imports, or a combination of the two. Then throughputs and the light product yield breakdown are changed until end-of-year kerosene jet fuel and distillate and average gasoline imports are at about the same level as in the previous year.

Application of the Supply /Demand Balance Model is illustrated with results of the Base Case Run. Table C-3 shows spreadsheet calculations for the year 2002. The summary tables for all the years is given in Table C-4. Any of the monthly variables can be plotted for the years in the projection period.

TABLE C-3. U.S. MAJOR LIGHT PETROLUM PRODUCT SUPPLY/DEMAND BALANCE MODEL—2002

Base Assumptions													
Annual Average Lt. Product Yield	81.33	Inventories on Jan 1			Annual Demands for Light Products								
Annual Average Kerosene & Kero Jet Yield	11.33	Total Gasoline		209.3			1997	1998	1999	2000	2001	2002	
Annual Average Gasoline, % Lt. Product	59.1	Distillate		138.4	Gasoline		8017	8112	8209	8307	8406	8506	
Lt. Yield Drop per 1%		Kero Jet		47.9	Distillate & Jet		5033	5183	5269	5356	5445	5535	
Increase in Gasoline Yield	0.9				Distillate		3435	3481	3528	3575	3623	3671	
Oxygenate Fraction of RFG	0.122				Jet & Kerosene		1664	1702	1741	1781	1822	1864	
Gross Crude Inputs	154				RFG/Gasoline		0.318	0.292	0.292	0.292	0.292	0.292	
Input Adjustment Factor	0.988				Distillation Cap		15452	15705	16002	16124	16333	16445	
Monthly Data Assumptions	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Avg.**
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31	
Estimate Max Operable Capacity Util	100	95	95	97	100	100	100	100	100	97	100	100	98.7
Monthly Lt. Yield Factor	1.014	1.005	0.997	0.99	0.987	0.981	0.984	0.98	0.997	1.012	1.031	1.022	1.000
Monthly Kero Jet Yield Factor	1.074	1.047	0.989	0.941	0.932	0.95	0.984	0.984	0.996	1.006	1.032	1.066	1.000
Monthly Gasoline Yield Delta	-0.35	-0.35	-0.34	0.5	0.93	0.98	1.00	0.43	-0.05	-1.00	-1.10	-1.10	-0.04
Gasoline Yield Adj. Add Range	0.75	1.1	0.95	0.2	0.8	0.6	1	0.25	0.7	1	1	1	
Gasoline Yield Adj. Add Range	-0.35	-0.65	-0.4	-0.5	-0.9	-0.8	-1	-0.4	-0.7	-1	-0.7	-0.3	
Gasoline Yield Adj. Add to Delta	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	
Monthly Data Assumptions													
nC4 as a % Adj. Gasoline	3.54	2.9	1.68	1.06	1	0.92	0.89	1.02	1.83	2.84	2.78	3.67	
Oxygenates as a % Adj. Gasoline	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	
Field as a % Adj. Gasoline	0.93	1.35	0.9	1.54	1.45	1.81	1.03	1.16	1.18	1.72	1.51	1.11	
Gasoline Demand Fraction Annual Avg.	0.918	0.958	0.984	0.996	1.013	1.036	1.04	1.042	1.000	1.005	0.996	1.012	1.000
Distillate Demand Fraction Annual Avg.	1.089	1.099	1.055	0.994	0.917	0.953	0.889	0.935	0.978	1.012	1.012	1.066	1.000
Kerosene & Kero Jet Demand Fraction Ann. Avg.	1.038	1.028	0.978	0.961	0.933	0.963	0.979	1.016	0.984	1.004	1.047	1.07	
Crude & Unfinished Lt. Product Supply	1.12	1.08	1.1	1.14	1.19	1.19	1.19	1.175	1.21	1.135	1.14	1.14	
Demand Estimates													
Gasoline	7809	8149	8370	8472	8617	8812	8846	8863	8506	8549	8472	8608	8506
Distillate	3998	4034	3873	3649	3366	3498	3264	3432	3590	3715	3715	3913	3671
Kero Jet	1935	1916	1823	1791	1739	1795	1825	1894	1834	1871	1952	1994	1864

TABLE C-3. CONTINUED (2 OF 3)

Trial Values: Thruput & Net Imports	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
Refinery Distillation Capacity	16445	16454	16464	16473	16482	16492	16501	16510	16520	16529	16538	16548	
Demand Based Crude & Unfinished Input	15205	15045	15287	15670	16133	16584	16383	16473	16654	15851	15925	16349	15963
Demand Based Crude Inputs Est.	14805	14645	14887	15270	15733	16184	15983	16073	16254	15451	15525	15949	15563
Unfinished Oil Input	400	400	400	400	400	400	400	400	400	400	400	400	400
Demand Based Gross Inputs	14959	14799	15041	15424	15887	16338	16137	16227	16408	15605	15679	16103	15717
Gross Inputs (Limited by Capacity or Demand)	14959	14799	15041	15424	15887	16338	16137	16227	16408	15605	15679	16103	15717
Crude & Unfinished Input	15205	15045	15287	15670	16133	16584	16383	16473	16654	15851	15925	16349	15963
Gasoline Blendstock Imports	120	140	140	260	300	300	240	220	170	120	120	100	186
Gasoline Blendstock to Field	100	90	90	70	30	30	30	70	70	70	90	90	69
Net Distillate Imports	100	80	70	60	50	50	40	40	20	0	-20	20	43
Net Kero Jet Imports	64	64	64	64	64	64	64	64	64	64	64	64	64
Capacity Utilization	91.0	89.9	91.4	93.6	96.4	99.1	97.8	98.3	99.3	94.4	94.8	97.3	95.3
Estimated Production (MB/D)													
Light Products Yield (% Crude & Unfinished)	82.68	81.94	81.29	80.72	80.48	79.99	80.24	79.91	81.29	82.51	84.06	83.33	81.54
Light Products	12571	12328	12427	12649	12984	13266	13145	13163	13538	13079	13386	13623	13013
Adjusted Gasoline	7357	7214	7274	7510	7764	7940	7870	7806	7963	7569	7733	7870	7656
nC4 to Gasoline	260	209	122	80	78	73	70	80	146	215	215	289	153
Oxygenates to Gasoline	272	267	269	278	287	294	291	289	295	275	286	291	283
Blendstocks to Gasoline	-20	0	-10	190	180	180	150	150	100	100	40	0	88
Refined Gasoline Total	7869	7691	7655	8057	8309	8487	8381	8324	8504	8159	8274	8450	8180
Field Gasoline	68	97	65	116	113	144	81	91	94	130	117	87	100
Total Gasoline Production	7938	7788	7720	8173	8422	8630	8462	8415	8597	8289	8391	8538	8280
Kero Jet Production	1850	1785	1713	1671	1704	1785	1827	1836	1879	1807	1862	1975	1808
Distillate Production	3364	3329	3441	3469	3516	3541	3449	3521	3696	3703	3791	3779	3550
Gasoline Balance													
Product Supplied	7809	8149	8370	8472	8617	8812	8846	8863	8506	8549	8472	8608	8506
Total Gasoline Production	7938	7788	7720	8173	8422	8630	8462	8415	8597	8289	8391	8538	8280
Net Fin Imports to Balance	111	291	360	279	295	232	254	238	129	100	161	260	226
Total Net Gasoline Imports	231	431	500	539	595	532	494	458	299	220	281	360	412
Stock Change (MB/D)	240	-70	-290	-20	100	50	-130	-210	220	-160	80	190	0
Stock Change (MMB)	7.4	-2.0	-9.0	-0.6	3.1	1.5	-4.0	-6.5	6.6	-5.0	2.4	5.9	-0.1

TABLE C-3. CONTINUED (3 OF 3)

Kero Jet Balance	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Avg.**
Product Supplied	1935	1916	1823	1791	1739	1795	1825	1894	1834	1871	1952	1994	1864
Kero Jet Production	1850	1785	1713	1671	1704	1785	1827	1836	1879	1807	1862	1975	1808
Net Imports	20	90	80	80	70	70	70	70	70	40	10	0	56
Stock Change to Balance (MB/D)	-65	-42	-30	-41	34	60	72	13	115	-25	-80	-20	-1
Stock Change to Balance (MMB)	-2.0	-1.2	-0.9	-1.2	1.1	1.8	2.2	0.4	3.5	-0.8	-2.4	-0.6	-0.2
Distillate Balance													
Product Supplied	3998	3600	3500	3500	3366	3498	3264	3432	3590	3715	3715	3913	3591
Production	3364	3329	3441	3469	3516	3541	3449	3521	3696	3703	3791	3779	3550
Net Imports	100	80	70	60	50	50	40	40	20	0	-20	20	43
Stock Change to Balance (MB/D)	-533	-191	11	29	200	93	225	129	125	-12	56	-115	1
Stock Change to Balance (MMB)	-16.5	-5.3	0.3	0.9	6.2	2.8	7.0	4.0	3.8	-0.4	1.7	-3.6	0.8
Ending Stocks													
Gasoline	216.8	214.8	205.8	205.2	208.3	209.8	205.8	199.3	205.9	200.9	203.3	209.2	
Kero Jet	45.9	44.8	43.8	42.6	43.7	45.5	47.7	48.1	51.5	50.8	48.4	47.8	
Distillate	121.8	116.5	116.8	117.7	123.9	126.6	133.6	137.6	141.4	141.0	142.7	139.1	
Yield Summary													
Adj Gasoline	48.4	48.0	47.6	47.9	48.1	47.9	48.0	47.4	47.8	47.8	48.6	48.1	
Kero Jet	12.2	11.9	11.2	10.7	10.6	10.8	11.1	11.1	11.3	11.4	11.7	12.1	
Distillate	22.1	22.1	22.5	22.1	21.8	21.4	21.0	21.4	22.2	23.4	23.8	23.1	
Total Lt. Yields	82.7	81.9	81.3	80.7	80.5	80.0	80.2	79.9	81.3	82.5	84.1	83.3	

TABLE C-4. U.S. MAJOR LIGHT PETROLUM PRODUCT SUPPLY/DEMAND BALANCE MODEL—SUMMARY

	1997	1998	1999	2000	2001	2002	Growth Rate
Annual Demands For Light Products							
Gasoline	8017	8112	8209	8307	8406	8506	1.19
Distillate	3435	3481	3528	3575	3623	3671	1
Kero Jet & Kerosene	1664	1702	1741	1781	1822	1864	2
Total Light Product	13116	13295	13478	13663	13851	14041	1.37
Distillation Capacity	15632	15705	16002	16124	16333	16445	1.02
Supply/Demand Estimates: Annual Averages							
Capacity Utilization	95.3	95.3	95.3	95.3	95.3	95.3	
Total Net Gasoline Imports	358	310	300	329	350	412	
Supply/Demand Estimates: May–Sept. Summer Season							
Capacity Utilization	98.2	98.2	98.3	98.2	98.2	98.2	
Total Net Gasoline Imports	417	370	361	391	412	475	
Annual Average Net Product Imports							
Gasoline	358	310	300	329	350	412	
Distillate	56	56	56	56	56	56	
Kero Jet & Kerosene	43	43	43	43	43	43	
Total Light Product	456	408	399	428	448	510	

CAPACITY PROJECTIONS BY PADD

This section describes the development of a forecast of refinery capacity for 1998 through 2002 for each of the five U.S. PADDs. The analysis leading to the forecast capacity consists of three steps:

1) Categorize and analyze growth patterns for the refineries in each PADD and estimate future growth rates

2) Analyze refinery closures and the population of future closure candidates as a basis for forecasting annual closures 1998 through 2002

3) Collect and review all construction reports of future refinery projects, compare with growth estimates, and, accounting for unrecorded projects (capacity creep), adjust growth estimates from the first step.

PADD I Projection of Refinery Capacity Changes: 1997–2002

The refinery capacity reported in EIA's *Petroleum Supply Annual* (1996) showed PADD I operable distillation capacity to be 1,642 MB/D as of January 1, 1997. For the analysis of capacity trends, the PADD I refineries were broken into the groups shown in Table C-5. (Full listing of refineries, by group, and their capacity are presented in the tables at the end of this Appendix.)

TABLE C-5. PADD I REFINERY GROUPS

Group	Description	Examples*
Large refineries	Refineries >70 MB/D	Tosco, Bayway, NJ; Sun, Marcus Hook, PA; Mobil, Paulsboro, NJ.
Small refineries	Refineries <70 MB/D	Citgo, Savannah, GA; Pennzoil, Rouseville, PA; United, Warren, PA.
Closed refineries	Refineries closed during 1987-1997	Cibro, Albany, NY; St. Mary's, St. Mary's, WV.

* The examples column does not list all refineries in the group.

Source of Data: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340 (96)/1.

A summary of the historical distillation and downstream capacity changes for these three groups is shown in Table C-6. The large refineries in PADD I have shown modest growth, while the small refinery group has shown little growth. Compared with other PADDs, there is little coking capacity in PADD I. Thus, while the small refinery group has a high growth rate for coking capacity, it has little impact on a volume basis. The closed refinery group for PADD I consists of eight refineries, all small, with a total capacity of 87 MB/D at the time of closing.

Table C-6. Changes in Refinery Capacity: PADD II, 1987–1997

Refinery Capacity Groups	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996*	1997†	Growth Rate: % 1987-97	Volume Change 1987-97
Capacities of Large Refineries													
Atmospheric Dist Capacity (MB/CD)	1136	1166	1182	1202	1207	1243	1273	1299	1348		1415	2.2	279
FCC Capacity (MB/SD)	561	555	534	546	561	566	574	601	598		623	1.0	62
Coking Capacity (MB/SD)	66	68	68	68	66	66	67	67	69		71	0.7	5
Capacities of Small Refineries													
Atmospheric Dist Capacity (MB/CD)	226	225	182	229	229	228	224	224	224		227	0.1	2
FCC Capacity (MB/SD)	48	47	47	48	48	48	48	48	48		50	0.5	2
Coking Capacity (MB/SD)	14	14	14	14	14	14	14	14	14		29	3.5	6
Capacities of Closed Refineries													
Atmospheric Dist Capacity (MB/CD)	87	86	70	74	52	59	46	0	0		0		-87
FCC Capacity (MB/SD)	0	0	0	0	0	0	0	0	0		0		0
Coking Capacity (MB/SD)	0	0	0	0	0	0	0	0	0		0		0
Capacities of All PADD I Refineries													
Atmospheric Dist Capacity (MB/CD)	1448	1477	1434	1505	1488	1530	1543	1523	1572		1642	1.3	194
FCC Capacity (MB/SD)	609	602	581	594	609	614	622	649	646		673	1.0	64
Coking Capacity (MB/SD)	79	81	81	81	80	80	81	81	83		90	1.3	11

* Energy Information Administration did not publish refinery capacity data in 1996.

† Capacity for 1997 adjusted to include Tosco, Trainer Refinery, which reopened in May 1997.

Source of Data: Energy Information Administration.

The estimates of future capacity are based on assessing both historical growth patterns and announced changes. The future capacity expansion projects that have been announced are shown in Table C-7.

TABLE C-7. REPORTED PADD I REFINERY PROJECTS IN PLANNING OR CONSTRUCTION

Company	Refinery Location	Reported Capacity Change			Source
		Distillation (MB/D)	FCC (MB/D)	Coking (MB/D)	
Tosco	Bayway, NJ	+45			*Oil & Gas Journal*, 4/13/98, p.64
United	Warren, PA	+5			*Octane Week*, 7/21/97, p.3
Valero (formerly Mobil)	Paulsboro, NJ	+10			*Octane Week*, 5/25/98, p.6

A summary of the PADD I actual and projected volume changes from 1997 to 2002 are shown in Table C-8. The 1997 capacity numbers[3] for the large refinery group were adjusted to account for the return to service in May 1997 of Tosco's Trainer refinery. The estimated increase in distillation capacity for the large refinery group from 1997 to 2002 is 119 MB/D. In the 1987 to 1997 period, increases at Tosco's Bayway refinery represent a large share of the distillation capacity increase. If Tosco's distillation capacity increase at Bayway from 1997 to 2002 is the 45 MB/D shown in Table C-7, and the remainder of the group is estimated to follow the historical trend, the capacity increase for the group would total 107 MB/D, which is not significantly different from the 119 MB/D estimated by extending the historical growth rate. FCC capacity is estimated to increase 30 MB/D, following the capacity creep trend that has characterized FCC capacity in the past. It is estimated that continuing refinery closures will reduce distillation capacity for the small refinery group by 40 MB/D in the 1997–2002 period. The net capacity increase for the PADD as a whole is projected to be 79 MB/D for distillation capacity, 32 MB/D for FCC, and 6 MB/D for coking.

[3] 1997 capacity values are as of January 1, 1997.

Table C-8. Projection of Refinery Capacity: PADD I, 1997–2002

	No. of Refineries	1987	1992	1997*	2002	Growth Rate: % 1987-97	Volume Change 1987-97	Growth Rate: % 1992-97	Volume Change 1992-97	Growth Rate: % 1997-02	Volume Change 1997-02
Capacities of Large Refineries †	9										
Atmospheric Distillation (MB/CD)		1136	1243	1415	1534	2.2	279	2.6	173	1.6	119
Fluid Catalytic Cracking (MB/S)		561	566	623	653	1.0	62	1.9	57	1.0	30
Coking (MB/SD)		66	66	71	76	0.7	5	1.3	5	1.4	5
Capacities of Small Refineries	8										
Atmospheric Distillation (MB/CD)		226	228	227	187	0.1	2	-0.1	-1	-3.8	-40
Fluid Catalytic Cracking (MB/SD)		48	48	50	52	0.5	3	1.0	3	0.6	2
Coking (MB/SD)		14	14	19	20	3.5	6	6.3	5	1.4	1
Capacities of Closed Refineries	8										
Atmospheric Distillation (MB/CD)		87	59	0	0		-87		-59		-8 /Yr‡
Fluid Catalytic Cracking (MB/SD)		0	0	0	0		0		0		
Coking (MB/SD)		0	0	0	0		0		0		
Capacities of All PADD I Refineries											
Atmospheric Distillation (MB/CD)		1448	1530	1642	1721	1.3	194	1.4	113	0.9	79
Fluid Catalytic Cracking (MB/SD)		609	614	673	705	1.0	64	1.9	60	0.9	32
Coking (MB/SD)		79	80	90	96	1.3	11	2.3	10	1.4	6

* Capacity for 1997 adjusted to include Tosco, Trainer Refinery which reopened in May 1997.

† The current count of the large refineries group is now 8, because of the merged operations of Sun Philadelphia refineries.

‡ The annual closure rate of -8 MB/CD per year is applied to the small refinery group in the 1997–2002 period.

Source of Data: Energy Information Administration.

PADD II Projection of Refinery Capacity Changes: 1997–2002

The EIA survey of refinery capacity[4] reported PADD II operable distillation capacity as of January 1, 1997 to be 3,444 MB/D. For this analysis, the refineries of PADD II were separated into four groups (Table C-9).

TABLE C-9. PADD II REFINERY GROUPS

Group	Description	Examples*
Large Refineries	Refineries >70 MB/D	Amoco, Whiting, IN; Marathon, Robinson, IL; BP, Toledo, OH.
Independent Refineries	Refineries >70 MB/D owned by independent refiners	Koch, St. Paul, MN; Clark, Blue Island, IL; Sun, Toledo, OH.
Small Refineries	Refineries <70 MB/D	Countrymark, Mt. Vernon, IN; Lion, El Dorado, AR; Wynnewood, Wynnewood, OK.
Closed Refineries	Refineries closed during 1987–1997	Coastal, El Dorado, KS; Barrett, Custer, OK; Indian, Lawrenceville, IL.

* The examples column does not list all refineries in the group.

Source of Data: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340 (96)/1.

A summary of the historical distillation, FCC, and coking capacity changes for these four groups is shown in Table C-10. Several characteristics of the capacity growth in PADD II distinguish it from other PADDs. The growth of distillation, FCC and coking capacity for the combined large, independent, and small refinery groups have been very balanced. In other PADDs, downstream unit capacity has frequently shown more rapid growth than distillation capacity. While we normally associate strong coking capacity growth with PADDs III and V, it has also been very strong in PADD II, for both the large and independent refinery groups. For the number of refineries operating in the region, and the capacity of the region, the level of PADD II refinery closures has been very high, particularly during the 1992–97 period. In total, 14 refineries were closed with capacity totaling 307 MB/D at the time of closing.

[4] Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340(96/)1.

Table C-10. Changes in Refinery Capacity: PADD II, 1987–1997													
Refinery Capacity Groups	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996***	**1997**	**Growth Rate: % 1987-97**	**Volume Change 1987-97**
Large Refinery Group													
Atmospheric Dist Capacity (MB/CD)	1943	1945	1901	1905	1879	1921	1945	1929	2003		2070	0.6	127
FCC Capacity (MB/SD)	687	724	727	735	739	750	751	758	758		787	1.4	100
Coking Capacity (MB/SD)	175	176	180	180	182	182	188	192	204		219	2.3	44
Independent Refinery Group													
Atmospheric Dist Capacity (MB/CD)	610	622	645	652	667	683	683	715	754		835	3.2	225
FCC Capacity (MB/SD)	241	241	241	241	261	266	268	276	256		270	1.1	29
Coking Capacity (MB/SD)	299	300	304	310	312	313	319	324	344		374	2.3	75
Small Refinery Group													
Atmospheric Dist Capacity (MB/CD)	510	507	506	506	514	517	515	515	525		540	0.6	29
FCC Capacity (MB/SD)	193	194	198	200	200	201	204	202	205		203	0.5	10
Coking Capacity (MB/SD)	15	15	15	15	15	15	15	15	16		16	0.7	1
Closed Refinery Group													
Atmospheric Dist Capacity (MB/CD)	218	208	211	215	270	269	256	156	166		0		-218
FCC Capacity (MB/SD)	71	68	70	69	103	97	97	50	50		0		-71
Coking Capacity (MB/SD)	5	5	5	5	5	5	5	0	0		0		-5
Total PADD II Refineries													
Atmospheric Dist Capacity (MB/CD)	3282	3281	3263	3277	3329	3389	3398	3314	3447		3444	0.5	163
FCC Capacity (MB/SD)	1191	1226	1236	1244	1303	1313	1320	1285	1268		1259	0.6	68
Coking Capacity (MB/SD)	494	496	503	510	513	514	527	531	563		609	2.1	115

* Energy Information Administration did not publish refinery capacity data in 1996.

Source: Energy Information Administration.

Future PADD II capacity expansion projects that have been announced are shown in Table C-11.

TABLE C-11. REPORTED PADD II REFINERY PROJECTS IN PLANNING OR CONSTRUCTION

Company	Refinery Location	Reported Capacity Change			Source*
		Distillation (MB/CD)	FCC (MB/D)	Coking (MB/D)	
Ashland	St. Paul, MN	+4.5			O&GJ, 4/13/98, p.64
BP	Toledo, OH			+28	O&GJ, 4/13/98, p.64
Citgo	Lemont, IL		+17.8		O&GJ, 4/13/98, p.64
Mapco	Memphis, TN	+10			O&GJ, 4/13/98, p.64

* O&GJ - *Oil &Gas Journal.*

A summary of the PADD II actual and projected volume changes from 1997 to 2002 are shown in Table C-12. For the forecast period, the large refinery and independent refinery groups are forecast to change at the same rate. For the 1987–97 historical period, FCC and coking capacity changes were similar for the two groups. The 1987–97 distillation capacity increase was much higher for the independent group because of the large expansion at Koch's St. Paul, MN, refinery and at Mapco's Memphis, TN, facility. Since there is not any evidence of large planned expansions at independent refineries (Table C-11), the independent and large refinery distillation capacity expansion for both groups is estimated at the combined overall rate for the 1987–97 period. Refinery capacity loss through closures is forecast to continue at the rate of 20 MB/D per year. Based on these assumptions, by 2002, PADD II distillation capacity will grow by 106 MB/D, FCC capacity by 40 MB/D, and coking by 67 MB/D.

Table C-12. Projection of Refinery Capacity: PADD II, 1997–2002

	No. of Refineries	1987	1992	1997	2002	Growth Rate:% 1987-97	Volume Change 1987-97	Growth Rate:% 1992-97	Volume Change 1992-97	Growth Rate:% 1997-02	Volume Change 1997-02
Capacities of Large Refinery Group	11										
Atmospheric Dist Capacity (MB/CD)		1943	1921	2070	2208	0.6	127	1.5	149	1.3	138
FCC Capacity (MB/SD)		687	750	787	839	1.4	100	1.0	37	1.3	52
Coking Capacity (MB/SD)		175	182	219	245	2.3	44	3.8	37	2.3	26
Capacities of Independent Refineries	7										
Atmospheric Dist Capacity (MB/CD)		610	683	835	891	3.2	225	4.1	152	1.3	56
FCC Capacity (MB/SD)		241	266	270	288	1.1	29	0.3	4	1.3	18
Coking Capacity (MB/SD)		299	313	374	418	2.3	75	3.6	61	2.3	44
Capacities of Small Refinery Group	11										
Atmospheric Dist Capacity (MB/CD)		510	517	540	452	0.6	29	0.9	23	0.6	-88
FCC Capacity (MB/SD)		193	201	203	172	0.5	10	0.2	2	0.6	-30
Coking Capacity (MB/SD)		15	15	16	13	0.7	1	1.3	1	0.6	-3
Capacities of Closed Refinery	14										
Atmospheric Dist Capacity (MB/CD)		218	269	0			-218		-269		-20/Yr*
FCC Capacity (MB/SD)		71	97	0			-71		-97		-7/Yr*
Coking Capacity (MB/SD)		5	5	0			-5		-5		
Capacities of All PADD II Refineries											
Atmospheric Dist Capacity (MB/CD)		3282	3389	3444	3551	0.5	163	0.3	56	0.6	106
FCC Capacity (MB/SD)		1191	1313	1259	1299	0.6	68	-0.8	-54	0.6	40
Coking Capacity (MB/SD)		494	514	609	676	2.1	115	3.4	95	0.6	67

* The annual closure rates of -20 MB/CD per year and -7 MB/SD per year are applied to the small refinery group in the 1997–2002 period.

Source of Data: Energy Information Administration.

PADD III Projection of Refinery Capacity Changes: 1997–2002

As of January 1, 1997, EIA reported that PADD III contained 7,093 MB/D of distillation capacity, which is the greatest of any of the PADDs.[5] This capacity was broken down into five groups of refineries (Table C-13) to better understand the drivers behind the capacity changes from 1987 to 1997 and improve the forecast of capacity growth through 2002.

TABLE C-13. PADD III REFINERY GROUPS

Group	Description	Examples*
Independents	Companies with downstream oil operations only (no exploration and production)	Valero, Corpus Christi, TX; UDS, Three Rivers, TX; Crown, Houston, TX.
Producing Governments	Companies with some foreign ownership interest	Citgo, Lake Charles, LA; Star, Convent, LA; Deer Park, Deer Park, TX; Lyondell Citgo, Houston, TX.
Multi-Train Refineries	Multi-train refineries >300 MB/D	Amoco, Texas City, TX; Exxon, Baytown, TX; Chevron (now Clark), Port Arthur, TX.
Large Refineries	Refineries 70-300 MB/D	Chevron, Pascagoula, MS; Conoco, Westlake, LA; Marathon, Garyville, LA,
Small Refineries	Refineries <70 MB/D	Placid, Port Allen, LA; Giant, Bloomfield, NM; Gold Line, Lake Charles, LA.

* The examples column does not list all refineries in the group.

Source of Data: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340 (96)/1.

A summary of the historical distillation and downstream capacity changes for these five groups is shown in Table C-14. The growth patterns and magnitudes are quite different for the groups.

1) The independent refiners group showed the highest rate of growth in distillation capacity and a moderate growth rate in FCC and coking capacity (1.1 and 0.8 percent, respectively).

[5] Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340(96)/1.

Table C-14. Changes in Refinery Capacity: PADD III, 1987–1997

Refinery Group	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996*	1997	Growth Rate:% 1987-97	Volume Change 1987-97
Independent Refiner Group													
Atmospheric Dist Capacity (MB/CD)	728	734	747	753	763	770	781	808	950		897	2.1	169
FCC Capacity (MB/SD)	388	397	415	420	421	421	417	420	424		431	1.1	43
Coking Capacity (MB/SD)	25	25	25	25	25	25	25	25	27		27	0.8	2
Foreign Interest Refineries													
Atmospheric Dist Capacity (MB/CD)	1423	1424	1411	1393	1416	1391	1391	1376	1376		1414	-0.1	-10
FCC Capacity (MB/SD)	550	563	563	566	572	600	600	530	529		546	-0.1	-5
Coking Capacity (MB/SD)	137	155	137	163	166	213	212	229	233		289	7.8	152
Large Multi-Train Refineries													
Atmospheric Dist Capacity (MB/CD)	1755	1755	1697	1591	1595	1566	1427	1438	1438		1480	-1.7	-275
FCC Capacity (MB/SD)	614	614	615	663	678	648	631	652	669		682	1.1	68
Coking Capacity (MB/SD)	161	162	165	161	195	181	192	193	203		218	3.1	57
Large Refineries													
Atmospheric Dist Capacity (MB/CD)	2075	2093	2128	2136	2148	2187	2247	2254	2338		2403	1.5	328
FCC Capacity (MB/SD)	731	738	664	672	691	790	815	829	833		882	1.9	150
Coking Capacity (MB/SD)	225	230	229	236	249	262	267	273	277		288	2.5	63
Small Refineries													
Atmospheric Dist Capacity (MB/CD)	819	816	832	837	848	876	864	880	893		901	1.0	82
FCC Capacity (MB/SD)	174	174	175	179	182	179	180	183	188		198	1.3	24
Coking Capacity (MB/SD)	21	21	21	19	19	19	19	22	22		19	-1.4	-3
Refineries Closed by 1998													
Atmospheric Dist Capacity (MB/CD)	289	322	247	154	137	175	54	44	15		0		-289
FCC Capacity (MB/SD)	66	62	27	27	43	43	16	16	0		0		-66
Coking Capacity (MB/SD)	13	13	13	13	13	13	9	9	0		0		-13
Total PADD III Refineries													
Atmospheric Dist Capacity (MB/CD)	7089	7143	7062	6863	6907	6964	6764	6801	7011		7093	0.0	4
FCC Capacity (MB/SD)	2523	2547	2458	2526	2587	2681	2658	2630	2643		2738	0.8	216
Coking Capacity (MB/SD)	582	604	589	615	665	711	722	750	761		840	3.7	258

* EIA did not publish refinery capacity data in 1996.

Source of Data: Energy Information Administration.

2) Virtually all the growth for the refiners with foreign ownership interest has been in coking, which increased a huge 7.8 percent annually, while distillate and FCC capacity showed no growth.

3) The multi-train group showed negative distillation capacity growth primarily because of Chevron's revision of the Port Arthur refinery to a single train configuration (Chevron since sold the refinery to Clark in 1995). From 1987 to 1994, Port Arthur distillation capacity was reduced from 406 MB/D to 185 MB/D and FCC capacity was reduced from 110 MB/D to 65 MB/D. Between 1987 and 1993, Exxon also reduced distillation capacity at Baytown from 493 to 421, and at Baton Rouge from 455 to 396 MB/D. However, between 1987 and 1997, Exxon refineries showed coking capacity growth, and all except the Chevron Port Arthur refinery showed FCC growth.

4) The large refinery group showed growth in distillation and downstream capacity, with the strongest growth in coking capacity at 2.5 percent.

5) The small refinery group showed modest growth in distillation and FCC capacity, but this is a group with little coking capability, and little change occurred in its coking capability.

Twenty refineries closed in PADD III that were either operating at the beginning of the period or started up during the period and operated over a three year period. The total capacity of these 20 refineries at the time of their closing was 374 MB/D. Only one of the 20 refineries was not in the small refinery category (less than 70 MB/D) at its time of closing. The average capacity of each of these closed refineries was 18.7 MB/D.

The analysis of reports of future refinery construction projects shows that similar patterns will continue over the next few years in PADD III, with perhaps a somewhat diminished emphasis on coking and a bit more emphasis on distillation capacity. The reported capacity expansion projects for PADD III are shown in Table C-15.

Much of the past expansion in FCC capacity has either not been reported in terms of the volume of expansion or, in a number of cases, has not been reported at all. Recent *Hydrocarbon Processing* and *Oil & Gas Journal* construction issues report FCC revamp work at Exxon Baton Rouge and Baytown; Citgo Lake Charles; Marathon Garyville; and the Deerpark refinery. Information on the changes in volume for any of these revamp projects was not reported.

The start-up and operation of the TransAmerican Refinery at Norco, LA, could add significant capacity to PADD III. TransAmerican appears to be a highly sophisticated facility with a 75-MB/D coker, 130-MB/D FCC, and 26-MB/D alkylation unit. There is a level of skepticism about operation of this refinery because of its past history. In the early 1980s, John R. Stanley expanded the small 7 MB/D Good Hope refinery to the 300 MB/D GHR refinery,

TABLE C-15. REPORTED PADD III REFINERY PROJECTS IN PLANNING OR CONSTRUCTION

Company	Refinery Location	Reported Capacity Change			Source
		Distillation (MB/D)	FCC (MB/D)	Coking (MB/D)	
Citgo	Corpus Christi, TX	+20			*Hydrocarbon Processing* Box Score 10/13/97
Clark	Port Arthur, TX	+20		+38	*21st Century Fuels* 5/98, p.5
Phillips	Sweany, TX			+58	Oil Express 4/1/97, p.3
UDS	Sunray, TX	+10			*Oil & Gas Journal* Box Score 10/13/97
Valero	All PADD III	+140			*Octane Week* 3/8/98, p.3
	Houston, TX	+20	+8		*Octane Week* 9/8/97
	Krotz Spring, TX	+40	+15		*Petroleum Argus* 1/19/98
	Texas City, TX	+40	+15		*Petroleum Argus Weekly*, 1/19/98
	Corpus Christi, TX		+4		*Octane Week*, 9/8/97

but the poor refining markets of the early eighties brought about bankruptcy by 1983. EIA listed the refinery as operable, but idle from November 1987 to December 1992. The conclusion of this analysis is that, given the currently expanded equipment capability of the refinery, the current U.S. capacity situation, and the eagerness of independents and foreign interests to engage in joint ventures, the refinery will become an operating refinery in the 1998–2002 time frame.

This forecast assumes that refinery closures will continue, principally from the small refinery group, with an estimated annual capacity loss of 18 MB/D of distillation capacity (Table C-16). A summary of the PADD III actual and projected volume changes from 1997 to 2002 are shown in Table C-16. As can be seen, more than half of the distillation capacity growth will come from the opening of the TransAmerican Refinery. The remainder of the growth will come from the independent and large refinery groups. No distillation capacity growth is forecast for the multi-train group or the foreign interest group, which is expected to maintain its focus on bottoms conversion. Overall, the capacity change forecasted is an increase of 535 MB/D of distillation capacity.

Table C-16. Projection of Refinery Capacity: PADD III, 1997–2002

	No. of Refineries	1987	1992	1997	2002	Growth Rate:% 1987-97	Volume Change 1987-97	Growth Rate:% 1992-97	Volume Change 1992-97	Growth Rate:% 1997-02	Volume Change 1997-02
Capacities of Independent Refineries	9										
Atmospheric Dist Capacity (MB/CD)		728	770	897	995	2.1	169	3.1	127	2.1	98
FCC Capacity (MB/SD)		388	421	431	464	1.1	43	0.5	10	1.5	33
Coking Capacity (MB/SD)		25	25	27	28	0.8	2	1.6	2	1.0	1
Capacities of Foreign Interest Refineries	6										
Atmospheric Dist Capacity (MB/CD)		1423	1391	1414	1414	-0.1	-10	0.3	23	0.0	0
FCC Capacity (MB/SD)		550	600	546	546	-0.1	-5	-1.9	-54	0.0	0
Coking Capacity (MB/SD)		137	213	289	319	7.8	152	6.3	77	2.0	30
Capacities of Large Multi-Train Refineries	4										
Atmospheric Dist Capacity (MB/CD)		1755	1566	1480	1480	-1.7	-275	-1.1	-86	0.0	0
FCC Capacity (MB/SD)		614	648	682	717	1.1	68	1.0	34	1.0	35
Coking Capacity (MB/SD)		161	181	218	258	3.1	57	3.8	37	3.5	41
Capacities of Large Refineries	12										
Atmospheric Dist Capacity (MB/CD)		2075	2187	2403	2586	1.5	328	1.9	216	1.5	183
FCC Capacity (MB/SD)		731	790	882	968	1.9	150	2.2	92	1.9	87
Coking Capacity (MB/SD)		225	262	288	326	2.5	63	1.9	26	2.5	38
Capacities of Small Refineries	30										
Atmospheric Dist Capacity (MB/CD)		819	876	901	854	1.0	82	0.6	25	-1.1	-47
FCC Capacity (MB/SD)		174	179	198	209	1.3	24	2.0	18	1.1	11
Coking Capacity (MB/SD)		21	19	19	19	-1.4	-3	0.0	0	0.0	0
Capacities of Closed Refineries	-20										
Atmospheric Dist Capacity (MB/CD)		289	137	0							-18/Yr*
FCC Capacity (MB/SD)		66	43	0							
Coking Capacity (MB/SD)		13	13	0							
Capacities of Refineries Opened: 1998-2002	1										
Atmospheric Dist Capacity (MB/CD)					300						300
FCC Capacity (MB/SD)					130						130
Coking Capacity (MB/SD)					75						75
Capacities of All PADD III Refineries											
Atmospheric Dist Capacity (MB/CD)		7089	6926	7093	7628	0.0	4	0.5	167	1.5	535
FCC Capacity (MB/SD)		2523	2681	2738	3034	0.8	216	0.4	57	2.1	296
Coking Capacity (MB/SD)		582	711	840	1025	3.7	258	3.4	129	4.1	185

* The annual closure rate of -18 MB/CD per year is applied to the small refinery group in the 1997–2002 period.

Source of Data: Energy Information Administration.

PADD IV Projection of Refinery Capacity: 1997–2002

Refinery capacity in PADD IV is the smallest of the five PADDs. As reported by EIA, operable distillation capacity on January 1, 1997, was 520 MB/D. For this analysis of capacity trends, the refineries of PADD IV were divided into three groups: large, small, and closed refineries (Table C-17). The large refinery group in PADD IV has been defined as those greater than 45 MB/D, which is a different definition than that used in the other PADDs. PADD IV is a less densely populated region with smaller refineries than in other regions. The large refinery group contains six refineries ranging from 45 to 57.5 MB/D. With the exception of several refineries near Denver and Salt Lake, refineries in PADD IV are dispersed across Wyoming and Montana.

TABLE C-17. PADD IV REFINERY GROUPS

Group	Description	Examples*
Large Refineries	Refineries >45 MB/D	Amoco, Salt Lake City, UT; Conoco, Commerce City, CO; Exxon, Billings, MT
Small Refineries	Refineries <45 MB/D	Cenex, Laurel, MT; Frontier, Cheyenne, WY; Phillips, Salt Lake City, UT.
Closed Refineries	Refineries closed during 1987–1997	Amoco, Casper, WY; Landmark, Fruita, CO; Pennzoil, Roosevelt, UT.

* The examples column does not list all refineries in the group.

Source of Data: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340 (96)/1.

A summary of the historical distillation, FCC, and coking capacity changes for these three groups is shown in Table C-18. Growth has been modest for the refineries operating in 1987 and continuing to operate. Overall distillation capacity growth was less than 1 percent (higher for the large refineries and lower for the smaller). FCC capacity growth was less than seen in other PADDs. Six refineries have closed taking away a total distillation capacity of 57 MB/D at time of closing, but that volume is dominated by the 40 MB/D Casper, WY, refinery that closed in 1991.

A summary of the PADD IV actual and projected volume changes from 1997 to 2002 is shown in Table C-19. Overall, PADD IV shows negligible volume growth with distillation capacity rising a mere 3 MB/D over the five-year period. Growth is projected for the large refinery group at the historical trend rate, but this is countered by an expected continuation of the decline in small, marginal refineries of 17 MB/D over the five-year period. The small refinery decline is forecast to be lower than the historical trend because the closure of a refinery the size of the 40 MB/D Amoco refinery is not expected to reoccur. The low growth assumptions used in Table C-19 are supported by the absence of any reported expansion activity in any PADD IV refinery.

Table C-18. Changes in Refinery Capacity: PADD IV, 1987–1997

Refinery Capacity Groups	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996*	1997	Growth Rate:% 1987-97	Volume Change 1987-97
Capacities of Large Refineries													
Atmos Distillation (MB/CD)	270	273	274	279	279	279	288	288	294		307	1.3	37
Fluid Catalytic Cracking (MB/SD)	109	109	109	114	116	116	116	110	112		113	0.4	4
Coking (MB/SD)	16	16	16	16	16	16	29	29	29		30	6.4	14
Capacities of Small Refiners													
Atmos Distillation (MB/CD)	207	213	213	213	213	213	213	214	214		214	0.3	7
Fluid Catalytic Cracking (MB/SD)	76	78	79	78	78	65	66	66	66		65	0.3	3
Coking (MB/SD)	9	9	9	9	9	9	10	10	10		10	1.1	1
Capacities of Closed Refineries													
Atmos Distillation (MB/CD)	57	54	63	63	63	18	18	8	0		0		-7/Yr†
Fluid Catalytic Cracking (MB/SD)	6	6	6	6	6	6	6	6	0		0		
Coking (MB/SD)	0	0	4	4	4	4	4	0	0		0		
Capacities of All PADD IV Refineries													
Atmos Distillation: MB/CD	534	540	550	555	555	510	519	510	508		520	-0.3	-14
Fluid Catalytic Cracking (MB/SD)	191	192	193	198	200	187	188	182	178		178	-0.7	-13
Coking (MB/SD)		25	29	29	29	29	43	39	39		40	0.0	15

* Energy Information Administration did not publish refinery capacity data in 1996.

† The annual closure rate of -7 MB/CD per year is applied to the small refinery group in the 1997–2002 period.

Source of Data: Energy Information Administration.

Table C-19. Projection of Refinery Capacity: PADD IV, 1997–2002	No. of Refineries	1987	1992	1997	2002	Growth Rate:% 1987-97	Volume Change 1987-97	Growth Rate:% 1992-97	Volume Change 1992-97	Growth Rate:% 1997-02	Volume Change 1997-02
Capacities of Large Refineries	6										
Atmos Distillation (MB/CD)		270	279	307	327	1.3	37	1.9	28	1.3	20
Fluid Catalytic Cracking (MB/SD)		109	116	113	115	0.4	4	-0.6	-3	0.4	2
Coking (MB/SD)		16	16	30	32	6.4	14	13.3	14	1.0	2
Capacities of Small Refiners	9										
Atmos Distillation (MB/CD)		207	213	214	197	0.3	7	0.0	0	-1.6	-17
Fluid Catalytic Cracking (MB/SD)		76	65	65	64	0.3	3	0.0	0	-0.4	-1
Coking (MB/SD)		9	9	10	11	1.1	1	2.1	1	1.0	1
Capacities of Closed Refineries	6										
Atmos Distillation (MB/CD)		57	18	0	0						-4/Yr *
Fluid Catalytic Cracking (MB/SD)		6	6	0	0						
Coking (MB/SD)		0	4	0	0						
Capacities of All PADD IV Refineries											
Atmos Distillation (MB/CD)		534	510	520	524	-0.3	-14	0.4	10	0.1	3
Fluid Catalytic Cracking (MB/SD)		191	187	178	179	-0.7	-13	-1.0	-9	0.1	1
Coking (MB/SD)		25	29	40	42	4.8	15	6.5	11	1.0	2

* The annual closure rate of -4 MB/CD per year is applied to the small refinery group in the 1997–2002 period.

Source of Data: Energy Information Administration.

PADD V Projection of Refinery Capacity Changes: 1997–2002

The EIA survey of refinery capacity reported PADD V operable capacity to be 2,932 MB/D as of January 1, 1997. For the analysis of PADD V capacity, the refineries in this region were separated into five groups (Table C-20). The factors prominent in the breakdown are refinery size and location. PADD V has a number of refining and marketing regions that are distinctively separate, which led to the geographic distinctions as well as size.

TABLE C-20. PADD V REFINERY GROUPS

Group	Description	Examples*
Pacific Northwest large Refineries	Refineries near Puget Sound and >70 MB/D	Arco, Cherry Point, WA; Shell Anacortes, WA; Tosco, Ferndale, WA.
California large Refineries	Refineries in California and >70 MB/D	Chevron, El Segundo; Exxon, Benicia; Mobil, Torrance.
Other PADD V large Refineries	Refineries in PADD V outside of WA and CA >70 MB/D	Mapco, North Pole, AK; Chevron, Honolulu, HI
Small Refineries	Refineries <70 MB/D	Huntway, Benicia, CA; Kern Oil, Bakersfield, CA; Petrostar, North Pole, AK.
Closed Refineries	Refineries closed during 1987–1997	Fletcher Oil, Carson, CA; Sunland Refining, Bakersfield, CA; Powerine, Santa Fe Springs, CA.

*The examples column does not list all refineries in the group.

Source of Data: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340 (96)/1.

A summary of the historical distillation and downstream capacity changes for these groups is shown in Table C-21. The Puget Sound refineries in Washington state have shown moderate growth from 1987 to 1997. Distillation capacity rose from 407 to 492 MB/D and FCC capacity rose from 100 MB/D to 124 MB/D. Capacity change for the large California refineries has been complicated. From 1987 to 1992, the large California refineries experienced a large decline in distillation capacity. Chevron reduced distillation capacity at El Segundo from 405 to 254 MB/D, and at Richmond from 350 to 220 MB/D; but FCC, coking, and hydrocracking capacity at these refineries either remained constant or increased. Unocal purchased Shell's Los Angeles refinery and combined it with its own Martinez refinery, keeping the best units from each refinery. The net result was the elimination of 108 MB/D of distillation capacity and a 42 MB/D FCC unit. From 1992 to 1997, the large California refinery group capacity grew 1.0 percent for distillation, 2.0 percent for FCC, and 2.1 percent for coking capacity.

Table C-21. Changes in Refinery Capacity: PADD V, 1987–1997

Refinery Groups	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996*	1997	Growth Rate:% 1987-97	Volume Change 1987-97
Pacific Northwest													
Atmos Distillation (MB/CD)	407	420	433	458	476	492	506	504	532		543	2.92	136
Fluid Catalytic Cracking (MB/SD)	100	100	013	116	119	122	121	122	123		124	2.20	24
Coking (MB/SD)	68	68	70	72	72	77	77	77	79		80	1.64	12
Large California													
Atmos Distillation (MB/CD)	1756	1781	1636	1602	1575	1419	1454	1446	1443		1492	-1.61	-264
Fluid Catalytic Cracking (MB/SD)	527	538	548	550	550	510	538	558	567		584	1.03	57
Coking (MB/SD)	306	326	332	330	336	332	333	342	345		368	1.86	62
Other PADD V Large													
Atmos Distillation (MB/CD)	276	278	289	307	331	335	341	346	348		352	2.47	76
Fluid Catalytic Cracking (MB/SD)	22	22	22	20	20	20	20	21	22		22	0.00	0
Coking (MB/SD)	0	0	0	0	0	0	0	0	0		0		0
PADD V Small													
Atmos Distillation (MB/CD)	534	499	498	504	509	476	509	511	512		545	0.20	11
Fluid Catalytic Cracking (MB/SD)	66	66	66	66	68	66	69	69	68		68	0.30	2
Coking (MB/SD)	111	109	107	108	135	143	143	142	135		137	2.11	26
Closed Refineries													
Atmos Distillation (MB/CD)	240	196	191	201	204	173	85	80	62		0		
Fluid Catalytic Cracking (MB/SD)	33	33	35	38	39	38	13	13	13		0		
Coking (MB/SD)	10	10	12	12	10	10	10	10	11		0		
Total PADD V Refineries													
Atmos Distillation (MB/CD)	3213	3174	3047	3072	3094	2895	2896	2887	2897		2932	-0.91	-281
Fluid Catalytic Cracking (MB/SD)	748	759	774	789	795	756	760	782	793		798	0.65	50
Coking (MB/SD)	0	513	521	522	553	562	563	571	570		0		585

* Energy Information Administration did not publish refinery capacity data in 1996.

Source of Data: Energy Information Administration.

The other PADD V large refinery group consists of two refineries in Alaska and two in Hawaii. These refineries have shown modest growth in distillation capacity. They have no coking capacity and only one has an FCC unit. Hydrocracking capacity exceeds FCC capacity for the group. The capacity changes in this group had little impact on the total PADD V picture.

The small PADD V refineries that have continued to operate experienced some increases in capacity; however, the refinery closures in PADD V have all come from this group, and they have been significant. In the 1987–97 period, 17 refineries representing 301 MB/D of distillation capacity at the time of closure ceased operations. Most of the closures occurred in California, and about two-thirds of the shutdowns were during the latter half of the period (1992 to 1997). As of January 1, 1997, there were still 15 small refineries in California listed as operable in EIA's survey.

For PADD V, the listing of reported capacity expansion projects consists of only two refinery projects (Table C-22).

TABLE C-22. REPORTED PADD V REFINERY PROJECTS IN PLANNING OR CONSTRUCTION

Company	Refinery Location	Reported Capacity Change			Source*
		Distillation (MB/D)	FCC (MB/D)	Coking (MB/D)	
Mapco	North Pole, AK	+80			O&GJ, 4/13/98, p.64
Arco	Carson, CA		†	†	O&GJ, 4/13/98, p.64

* O&GJ - *Oil &Gas Journal.*
† Debottlenecking.

A summary of the PADD V actual and projected volume changes from 1997 to 2002 are shown in Table C-23. The large refinery groups in Puget Sound, California, and the rest of PADD V are forecast to make significant contributions to distillation capacity growth. This growth, however, is offset by continuation of closures in the small refinery group, which is anticipated to lose an annual average of 23 MB/D of distillation capacity, and 3 MB/D of FCC capacity. This leaves a net increase of 90.2 MB/D of distillation capacity for the PADD from in total from 1997 through 2002. Downstream unit capacity growth will continue to exceed distillation capacity growth primarily because there is little loss of FCC or coking capacity associated with the closures of small refineries. The result is an average capacity growth rate of about 1.5 percent for both FCC and coking capacity.

Table C-23. Projection of Refinery Capacity: PADD V, 1997–2002

Refinery Groups	No. of Refineries	1987	1992	1997	2002	Growth Rate: % 1987-97	Volume Change 1987-97	Growth Rate: % 1992-97	Volume Change 1992-97	Growth Rate: % 1997-02	Volume Change 1997-02
Pacific Northwest	5										
Atmos Dist Capacity (MB/CD)		407	492	543	599	2.92	136	2.0	51	2.0	56
FCC Capacity (MB/SD)		100	122	124	137	2.20	24	0.4	2	2.0	13
Coking Capacity (MB/SD)		68	77	80	84	1.64	12	0.9	4	1.0	4
Large California	10										
Atmos Dist Capacity (MB/CD)		1756	1419	1492	1570	-1.61	-264	1.0	74	1.0	78
FCC Capacity (MB/SD)		527	510	584	645	1.03	57	2.7	74	2.0	61
Coking Capacity (MB/SD)		306	332	368	408	1.86	62	2.1	36	2.1	40
Other PADD V Large	4										
Atmos Dist Capacity (MB/CD)		276	335	352	398	2.47	76	1.0	17	2.5	46
FCC Capacity (MB/SD)		22	20	22	24	0.00	0	1.9	2	2.0	2
Coking Capacity (MB/SD)		0	0	0	0		0		0	0.0	0
PADD V Small	20										
Atmos Dist Capacity (MB/CD)		534	476	545	455	0.20	11	2.7	69	-3.6	-90
FCC Capacity (MB/SD)		66	66	68	55	0.30	2	0.6	2	-4.2	-13
Coking Capacity (MB/SD)		111	143	137	137	2.11	26	-1.0	-7		0
Closed Refineries	17										
Atmos Dist Capacity (MB/CD)		240	173	0	0		-301				-23/Yr*
FCC Capacity (MB/SD)		33	38	0	0		-38				-3/Yr*
Coking Capacity (MB/SD)		10	10	0	0		-10				
Total PADD V Refineries											
Atmos Dist Capacity (MB/CD)		3213	2895	2932	3022	-0.91	-281	0.3	37	0.6	90
FCC Capacity (MB/SD)		748	756	798	860	0.65	50	1.1	42	1.5	63
Coking Capacity (MB/SD)		495	562	585	629	1.67	89	0.8	23	1.5	44

* The annual closure rates of -23 MB/CD per year and -3 MB/SD per year are applied to the small refinery group in the 1997-2002 period.

Source of Data: Energy Information Administration.

ATMOSPHERIC DISTILLATION CAPACITY OF PADD I REFINERIES BY REFINERY GROUP (MB/D)

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996*	1997
Coastal Eagle Point Oil Co.	Eagle Point	90	90	90	104.5	104.5	104.5	104.5	117	125		133
Chevron USA Inc.	Perth Amboy	80	80	80	80	80	80	80	80	80		80
Mobil Oil Corp.	Paulsboro	100	100	100	100	100	100	113	13	126		152
Star Enterprise	Delaware City	140	140	140	140	140	140	140	140	140		140
Sun Co. Inc.	Marcus Hook	155	165	170	175	175	175	175	175	175		175
Sun Refining & Marketing Co.	Philadelphia	125	125	125	125	130	130	130	130	315		315
Sun (Chevron)	Philadelphia	174.1	174.1	175	175	175	175	172.8	172	0		0
Tosco Refining Co.	Bayway	100	120	130	130	130	170	190	200	215		240
Tosco (BP)	Trainer	172	172	172	172	172	168	168	172	172		0
Large Refineries	PADD I	1136.1	1166.1	1182	1201.5	1206.5	1242.5	1273.3	1299	1348		1235
Amoco Oil Co.	Yorktown	51	51	51	53	53	53	53	53	53		56.7
Citgo Asph Refining Co.	Paulsboro	44.4	44.4	0	44.4	44.4	44.4	40	40	40		40
Citgo Asph Refining Co.	Savannah	28	28	28	28	28	28	28	28	28		28
Pennzoil Producing Co.	Rouseville	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7		15.7
Quaker State Oil Refining Corp.	Congo	12.15	12.15	12.15	12.5	12.5	11.5	11.5	11.5	11.5		11.5
United Refining Co.	Warren	60	60	60	60	60	60	60	60	60		60
Witco Corp.	Bradford	8.5	8.5	9.915	9.915	9.915	9.915	9.915	10	10		10
Young Refining Corp.	Douglasville	6	5.65	5.079	5.079	5.54	5.54	5.54	5.54	5.54		5.54
Small Refineries	PADD I	225.75	225.41	181.84	228.59	229.06	228.06	223.66	223.74	223.74		227.44

* Energy Information Administration did not publish refinery capacity data in 1996. This applies to all PADDs.

ATMOSPHERIC DISTILLATION CAPACITIES OF PADD II REFINERIES BY REFINERY GROUP (MB/D)

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Amoco Oil Co.	Whiting	350	350	350	350	350	370	395	400	410		410
Ashland Oil Inc.	Catlettsburg	213	213	213	213	213	213	213	213	213		219
BP Oil Co.	Lima	171	171	168	168	140	145	145	145	161		162
BP Oil Co.	Toledo	126	126	126	126	126	126	126	126	136		152
Conoco Inc.	Ponca City	134	134	136	140	140	140	140	140	140		155
Marathon Oil Co.	Detroit	69	69	69	69	70	70	70	70	70		70
Marathon Oil Co.	Robinson	195	195	160	160	160	175	175	175	175		175
Mobil Oil Corp.	Joliet	180	180	180	180	180	180	180	180	188		200
Shell Oil Co.	Wood River	274	274	274	274	274	274	273	252	268		275
Texaco Refining & Marketing	El Dorado	80	82	78	78	78	80	80	80	95		99
UNO-VEN Co., The	Lemont	151	151	147	147	147	147	147	147	147		154
Large Refineries	PADD II	1943	1945	1901	1905	1879	1921	1945	1929	2003		2070
Clark Refining & Marketing	Blue Island	65	65	65	65	65	65	65	72	81		81
Farmland Indus	Coffeyville	57	57	57	57	57	57	57	62	69		112
Koch Refining Co.	Pine Bend	155	155	180	185	200	200	200	220	230		250
Mapco Petroleum Inc.	Memphis	60	60	58	60	60	76	76	76	89		105
National Coop Refinery	McPherson	71	76	76	76	76	76	76	76	76		74
Sun Co. Inc.	Toledo	118	125	125	125	125	125	125	125	125		129
Sun Co. Inc.	Tulso	85	85	85	85	85	85	85	85	85		85
Independent Refineries	PADD II	610	622	645	652	667	683	683	715	754		835
Amoco Oil Co.	Mandan	58	58	58	58	58	58	58	58	58		58
Ashland Oil Inc.	Canton	66	66	66	66	66	66	66	66	66		66
Ashland Oil Inc.	Saint Paul Park	67	67	67	67	67	67	67	67	67		69
Clark Refining & Marketing	Hartford	64	64	64	57	57	57	57	57	63		64
Countrymark Coop	Mount Vernon	21	21	21	21	21	21	21	21	22		22
Murphy Oil USA Inc.	Superior	32	32	32	33	33	33	33	33	33		36
Sinclair Oil Corp.	Tulsa	50	47	47	47	47	50	50	50	54		57
Somerset Refinery Inc.	Somerset	6	6	6	6	6	6	6	6	6		6
Total Petroleum Inc.	Alma	42	42	42	46	46	46	46	46	46		51
Total Petroleum Inc.	Ardmore	62	62	61	61	68	68	68	68	68		68
Wynewood Refining	Wynnewood	43	43	43	45	45	45	43	43	43		43
Small Refineries	PADD II	510	507	506	506	514	517	515	515	525		540

ATMOSPHERIC DISTILLATION CAPACITIES OF PADD III REFINERIES BY REFINERY GROUP (MB/D)

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Basis Petroleum Inc.	Houston	65	65	65	66	71	71	71	71	71		71
Basis Petroleum Inc.	Krotz Springs	57	56	58	58	58	60	60	60	60		60
Basis Petroleum Inc.	Texas City	120	120	120	120	120	120	124	124	124		149
Crown Central Petroleum	Pasadena	100	100	100	100	100	100	100	100	100		100
Diamond Shamrock Refining & Marketing	McKee	91	100	105	110	110	112	115	125	132		140
Diamond Shamrock Refining & Marketing	Three Rivers	47	45	51	51	51	53	53	70	75		83
Koch Refining Co.	West Plt.	125	125	125	125	125	125	125	125	255		264
Koch – Southwestern Refining	Corpus East Plt.	104	104	104	104	104	104	104	104	104		0
Valero Refining Co.	Corpus Christi	19	19	20	20	25	25	30	30	30		30
Independent Refineries	PADD III	728	734	747	753	763	770	781	808	950		897
CITGO Petroleum Corp.	Lake Charles	320	320	305	282	305	305	305	305	305		305
CITGO Refining & Chemical Inc.	Corpus Christi	154	155	130	130	130	130	130	130	130		133
Deer Park Refining Ltd. Partnership	Deer Park	214	214	216	216	216	216	216	216	216		256
Lyondell CITGO Refining Co. Ltd.	Houston	260	260	285	290	290	265	265	265	265		255
Star Enterprise	Louisianna Plt.	225	225	225	225	225	225	225	225	225		230
Star Enterprise	Port Arthur Plt.	250	250	250	250	250	250	250	235	235		235
Foreign Interest Refineries	PADD III	1423	1424	1411	1393	1416	1391	1391	1376	1376		1414
Amoco Oil Co.	Texas City	400	400	420	415	433	433	433	433	433		433
Clark (Chevron)	Port Arthur	407	407	329	329	315	316	177	185	185		204
Exxon Co. USA	Baton Rouge	455	455	455	421	421	421	421	424	424		432
Exxon Co. USA	Baytown	493	493	493	426	426	396	396	396	396		411
Very Large Refineries	PADD III	1755	1755	1697	1591	1595	1566	1427	1438	1438		1480
BP Oil Co.	Alliance	199	199	214	214	218	218	223	223	232		250
Chevron USA Inc.	Pascagoula	295	295	295	295	295	295	295	295	295		295
Coastal Refining & Marketing	Corpus Christi	88	90	90	85	85	85	85	85	95		95
Conoco Inc.	Westlake	157	157	157	160	160	165	175	182	191		226
Fina Oil & Chemical Co.	Port Arthur	90	90	110	110	110	144	144	144	175		179
Marathon Oil Co.	Garyville	255	255	255	255	255	255	255	255	255		255
Mobil Oil Corp.	Beaumont	275	275	275	275	275	275	310	310	315		311
Mobil Oil Corp.	Chalmette	130	145	145	160	160	160	170	170	170		159
Murphy Oil USA Inc.	Meraux	93	93	93	88	95	95	95	95	100		95
Phillips 66 Co.	Borger	105	105	105	105	105	105	105	105	110		120
Phillips 66 Co.	Sweeny	175	175	175	175	175	175	175	175	185		200
Shell Oil Co.	Norco	215	215	215	215	215	215	215	215	215		218
Large Refineries	PADD III	2075	2093	2128	2136	2148	2187	2247	2254	2338		2403

ATMOSPHERIC DISTILLATION CAPACITIES OF PADD III REFINERIES BY REFINERY GROUP (MB/D) - CONTINUED

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Age Refining Inc.	San Antonio							5	4	6		7
Calcasieu Refining Co.	Lake Charles	14	14	14	14	14	13	13	13	13		14
Calumet Lubes Co., LP	Cotton Valley	8	8	8	8	8	8	8	8	8		8
Canal Refining Co.	Church Point	8	8	8	8	8	8	10	10	10		10
Chevron USA, Inc.	El Paso	76	76	66	66	66	66	65	82	87		90
Ergon Refining Inc.	Vicksburg	21	21	21	21	21	21	23	23	23		23
Fina Oil & Chemical Co.	Big Springs	55	55	55	55	55	55	55	55	55		55
Giant Industries Inc.	Bloomfield	17	17	17	17	17	17	17	17	17		17
Giant Refining Co.	Ciniza	18	18	18	19	20	20	21	21	21		21
Gold Line Refining Ltd.	Lake Charles			27	27	27	28	28	28	28		28
Howell Hydrocarbons & Chemical	Channelview	10	5	5	5	5	2	1	1	1		1
Hunt Refining Co.	Tuscaloosa	34	34	34	34	34	34	34	34	34		34
La Gloria Oil & Gas Co.	Tyler	46	46	46	46	55	55	55	52	55		55
Lion Oil Co.	El Dorado	48	48	48	48	48	48	48	50	51		52
Marathon Oil Co.	Texas City	70	70	70	70	70	70	70	70	70		70
Navajo Refining Co.	Artesia	35	35	35	38	38	57	57	57	57		57
Neste Trifinery Petroleum	Corpus Christi	30	27	27	27	27	27	27	27	27		27
Pennzoil Producing Co.	Shreveport	46	46	46	46	46	46	46	46	46		46
Placid Refining Co.	Port Allen	43	46	46	46	46	49	49	49	49		49
Pride Refining Inc.	Abilene	43	43	43	43	43	43	43	43	43		43
Shell Chemical Co.	Mobile	80	80	80	80	80	80	71	71	71		75
Shell Chemical Co.	Saint Rose	32	35	34	34	34	40	40	40	40		38
Shell Oil Co.	Odessa	29	29	29	29	29	29	29	29	29		28
Southland Oil Co.	Lumberton	6	6	6	6	6	6	6	6	6		6
Southland Oil Co.	Sandersville	11	11	11	11	11	11	11	11	11		11
Small Refineries	PADD III	777	774	790	795	805	830	829	844	855		862
Berry Petroleum Co.	Stephens	4	4	4	4	5	6	7	7	7		7
Calumet Lubes Co. LP	Princeton	4	4	4	4	4	6	6	6	8		8
Coastal Mobile Refining	Chickasaw	27	27	27	27	27	27	15	17	17		17
Cross Oil Refining & Marketing	Smackover	7	7	7	7	7	7	7	6	6		6
Petrolite Corp.	Kilgore	1	1	1	1	1	1	1	1	1		1
Small Special Refineries	PADD III	42	42	42	42	44	46	36	36	39		38

ATMOSPHERIC DISTILLATION CAPACITIES OF PADD IV REFINERIES BY REFINERY GROUP (MB/D)

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Amoco Oil Co.	Salt Lake City	40	40	40	40	40	40	40	40	44		52
Chevron USA Inc.	Salt Lake City	45	45	45	45	45	45	45	45	45		45
Conoco Inc.	Billings	49	49	49	50	50	50	50	50	50		52
Conoco Inc.	Commerce City	42	43	44	48	48	48	58	58	58		58
Exxon Co. USA	Billings	42	42	42	42	42	42	42	42	44		46
Sinclair Oil Corp.	Sinclair	53	54	54	54	54	54	54	54	54		54
Large Refineries	PADD IV	270	273	274	279	279	279	288	288	294		307
Big West Oil Co.	North Salt Lake	24	24	24	24	24	24	24	24	24		24
Cenex	Laurel	41	41	41	41	41	41	41	41	41		41
Colorado Refining Co.	Commerce City	28	34	28	28	28	28	28	28	28		28
Crysen Refining Inc.	Woods Cross	12	13	13	13	13	13	13	13	13		13
Frontier Refining Co.	Cheyenne	34	34	39	39	39	39	39	39	39		39
Little Amer. Refining Co.	Casper	25	25	25	25	25	25	25	25	25		25
Montana Refining Co.	Great Falls	6	6	7	7	7	7	7	7	7		7
Phillips 66 Co.	Woods Cross	25	25	25	25	25	25	25	25	25		25
Wyoming Refining Co.	Newcastle	13	13	13	13	13	13	13	13	13		13
Small Refineries	PADD IV	207	213	213	213	213	213	213	214	214		214

ATMOSPHERIC DISTILLATION CAPACITIES OF PADD V REFINERIES BY REFINERY GROUP (MB/D)

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Arco Producing Co.	Cherry Point	163	162	163	167	167	175	184	179	189		202
Shell Oil Co.	Anacortes	77	82	84	85	89	89	94	97	101		108
Sound Refining Inc.	Tacoma	12	12	12	12	12	12	12	12	12		12
Texaco Refining & Marketing Inc.	Puget Sound	78	87	97	117	130	132	132	132	136		132
Tosco Refining Co.	Ferndale	77	77	77	77	77	84	84	84	95		89
Pacific NW Refineries	Puget, WA	407	420	433	458	476	492	506	504	532		543
Arco Producing Co.	Los Angeles	216	214	214	222	223	223	237	237	237		255
Chevron USA Inc.	El Segundo	405	405	330	286	254	254	244	226	230		258
Chevron USA Inc.	Richmond	350	350	270	270	270	220	229	235	230		225
Exxon Co. USA	Benicia	121	126	128	128	128	128	128	128	128		128
Mobil Oil corp.	Torrance	123	123	123	123	123	123	130	130	130		130
Shell Oil Co.	Martinez	135	140	140	140	140	144	147	147	149		155
Tosco Refining Co.	Avon	126	126	126	132	132	132	145	148	160		138
Unocal Corp.	Los Angeles	108	108	108	108	108	122	122	122	106		128
Unocal Corp.	San Francisco	70	77	72	73	77	73	73	73	73		76
Unocal (Shell)	LA (Carson)	102	112	125	120	120	0	0	0	0		0
Large California Refineries	SF & LA Areas	1756	1781	1636	1602	1575	1419	1454	1446	1443		1492
BHP Petroleum Americas Refining	Ewa Beach											
Chevron USA Inc.	Honolulu	48	48	48	53	53	53	53	53	54		
Mapco Alaska	North Pole	90	90	90	104	113	117	123	128	128		
Tesoro Petroleum Corp.	Kenai	72	72	72	72	72	72	72	72	72		
Other Large Refineries	Alaska & Hawaii	210	210	210	229	238	241	248	253	254		0
Arco Alaska Inc.	Kuparuk	12	12	12	12	12	12	12	12	12		12
Arco Alaska Inc.	Prudhoe Bay	22	20	12	13	14	15	15	15	15		15
Edgington Oil Co.	Long Beach	42	42	42	42	42	0	0	0	0		0
Edgington Oil Co.	Long Beach	0	0	0	0	0	0	0	15	11		11
Huntway Refining Co.	Benicia	7	9	9	9	9	9	9	9	9		9
Huntway Refining Co.	Wilmington	6	6	6	6	6	6	6	6	6		6
Kern Oil & Refining Co.	Bakersfield	21	21	21	21	21	21	21	21	21		21

ATMOSPHERIC DISTILLATION CAPACITIES OF PADD V REFINERIES BY REFINERY GROUP (MB/D) - CONTINUED

Refinery	Location	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Lunday Thagard Co.	South Gate	8	8	8	8	8	8	8	8	8		8
Pacific Refining Co.	Hercules	55	55	55	55	55	55	55	50	50		50
Paramount Petroleum Corp.	Paramount	47	47	47	47	47	47	47	47	47		43
Petro Source Refining Partnership	Eagle Springs	0	0	0	0	0	7	7	7	7		7
Petro Star Inc.	North Pole	7	7	7	7	7	7	8	8	10		14
Petro Star Inc.	Valdez	0	0	0	0	0	0	26	26	26		38
San Joaquin Refinery Co. Inc.	Bakersfield	24	24	24	24	24	24	24	24	24		24
Santa Maria Refinery Co.	Santa Maria	10	10	10	10	10	10	10	0	0		10
Tenby Inc.	Oxnard	4	4	4	4	4	4	4	4	4		4
Texaco Refining & Marketing Inc.	Bakersfield	38	41	47	48	48	48	54	54	56		58
Texaco Refining & Marketing Inc.	Los Angeles	75	57	57	57	64	64	64	64	64		69
Texaco (Paramount)	Bakersfield	21	0	0	0	0	0	0	0	0		0
Ultramar Refining	Wilmington	64	65	65	69	66	68	68	68	68		68
Unocal Corp.	Santa Maria	41	41	41	41	41	40	40	41	42		40
US Oil & Refining Co.	Tacoma	32	32	32	32	32	32	32	32	32		40
Small Refineries	PADD V	534	499	498	504	509	476	509	511	512		545