CALIFORNIA
ENERGY
COMMISSION

SPRING 2006 PETROLEUM FUELS PRICE SPIKE
REPORT TO THE GOVERNOR

APPENDICES

AUGUST 2006
CEC-600-2006-012-AP

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Market Trends and Outlook for Refined Product Supply in California and the U.S., with an Overview of Major Refiner Profitability

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California Energy Commission

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AUGUST 11, 2006
CEC-600-2006-012-APA

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ACKNOWLEDGEMENTS

This report was prepared in collaboration with the staff of the California Energy Commission, including personnel from the California Board of Equalization for this study. ICF International wishes to express our appreciation for their very timely and responsive support during this project development. In addition, the information and data provided by Bruce Wilson of Wilson-Gillette & Co in Arlington, Virginia on Jones Act tanker history and activity was invaluable.

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REPORT OVERVIEW

On April 25, 2006, the California Energy Commission was directed by Governor Schwarzenegger to investigate the causes of the recent rapid increase in gasoline and diesel fuel prices in California. The purpose of this report is to assist Energy Commission staff with some of the analysis required to produce the report to the Governor.

ICF International (ICFI) has been requested to evaluate two key areas related to the investigation. Task 1 examines how the petroleum industry refining sector has changed over the past 10 years in California, the United States, and globally. It assesses the trends in refinery capacity, utilization, and yields, demand for fuel products, and import requirements over the period, and determines the outlook for supply in California and the United States through 2012.

Task 2 examines oil industry profits in several ways. It examines profits for the petroleum industry in comparison with other manufacturing companies over the past ten years, and specific profit levels and return on capital of the largest oil companies with significant presence in the U. S. market. This task will also provide comments on a report by Ernst & Young on the capital spending strategies of the major oil companies.

The two tasks provide a perspective of the oil refining market over the past ten years, both from an operational as well as a financial perspective, and a forecast of how the market may be changing through 2012 based on known changes and forecast supply and demand trends. The analysis indicates that some significant changes may be emerging in the U.S. market as a whole, and that California, as well as Arizona and Nevada, are likely facing sustained dependence on imported petroleum and ethanol supply through the study period.

The report is presented in two parts. Task 1 will be addressed initially, focusing on the supply and demand analysis, followed by the financial comparisons in Task 2.

EXECUTIVE SUMMARY

Background

This report was requested by the California Energy Commission to provide an analysis of both historical trends and a forward outlook for the supply and demand for fuel products in California and the U.S. through 2012. The report also analyzes the financial performance of the oil industry in the U.S. against other manufacturing sector business areas, as well as the profit trends of the integrated major oil companies and key independent refiners.

The investigation requested by the Governor was stimulated by the supply and price events in California in the spring of 2006. However, the timing of the request is opportune for a number of reasons.

The global oil supply and demand balance has been marked by substantial change in the past several years. Global demands for oil products are increasing as world economies grow, with China, India, and the Far East significantly increasing their thirst for fossil fuels. Accelerated demands, slower pace of new crude production streams, and depletion of existing fields have caused a reduction in spare crude oil production capacity globally. Tight crude spare capacity leads to a higher commodity price for crude oil. This increases revenue and income for national oil companies, as well as for major integrated oil companies or other companies with crude production assets.

Economic recovery and increased personal vehicle consumption have caused worldwide refining capacity to become stretched in meeting the rising demands in the Far East and the continued increases in the U.S. The tight refining capacity widens the premiums realized for gasoline and distillate over the rising cost of crude oil. Tight refining capacity therefore can create higher income for integrated majors and refiners.

This business climate has emerged because of higher demand levels, but also from the coincident trend in many countries to improve the environment. Reductions in sulfur levels in gasoline and diesel are taking place worldwide, and within the United States, California has been aggressive in stipulating gasoline and diesel formulations to mitigate damage to the state's fragile environment. The further reductions in gasoline sulfur and introduction of Ultra Low Sulfur Diesel (ULSD) nationwide in 2006, reductions in off-road diesel sulfur coming in 2010, and the elimination of the oxygenate requirement in reformulated fuels in 2006 from the 2005 Energy Policy Act, all impact refinery capability.

At the same time, a burgeoning ethanol industry in the United States is responding to demands for oxygenates to replace MTBE in gasoline in reformulated gasoline markets, and to blend in gasoline in other markets to reduce fossil fuel dependence.

The growth pattern for ethanol production could mean that 2012 Renewable Fuel Standards (RFS) production targets are met as early as the end of 2007.

Post Hurricanes Katrina and Rita, several U.S. Gulf Coast refiners, as well as those in other PADDs, have announced refinery expansion projects and/or upgrading projects. The additional supply from the refinery projects, coupled with increased ethanol penetration, can mean some significant changes may be occurring regarding U.S. product import dependence.

For California, the increased demand levels will place additional strain on the existing refinery system and distribution infrastructure, which has seen only minor capacity changes in the past 10 years. During this period, California refiners focused on investments to meet CARBOB gasoline (Phase 2 and 3), CARB diesel, and ULSD, rather than on expansion. Additionally, California is the primary conduit for fuel supply to Arizona and Nevada, states with high growth demand. With refiners in California hesitant to invest because of offset requirements for air emissions, permitting risks, and potential issues related to port access, higher demands in the three-state region may result in increased product dependency.

Data Sources

This report incorporates information and data from a number of data sources to develop a historical perspective and longer term petroleum product outlook for both California and the U.S. Primary contributing sources include:

- California Energy Commission records on petroleum product demand, refinery production, MTBE usage, stock levels, crude oil production, and forecasts.
- U.S. Department of Energy's Energy Information Administration (EIA) data records on refinery capacities, crude runs and yields, U.S. demands, and forecast national demands from the 2006 Annual Energy Outlook (AEO), and other sources as cited.
- The John S. Herold database of petroleum company financial and operating performance data
- Assessment of Jones Act movements of Petroleum products from the U.S. Gulf Coast to California from 1995 to current by Wilson-Gillette Consultants, Arlington, Virginia
- BP Statistical Review of World Energy June 2006
- ICF International (ICFI) assessment of refinery capacity additions based on public announcements from company websites, Oil and Gas Journal articles, Platt's Oilgram and Oil Daily articles.
- Forecasts of ethanol production growth based on the Renewable Fuel Association website (www.ethanolrfa.org), and publicly available records on new ethanol plants under consideration.

The data utilized were the best information available in the analysis period for this project. Judgment was necessary in determining the most reasonable data to use when more than one source provided similar information.

Key Findings

The report covers a broad range of issues relating to supply and demand in the Petroleum Industry Trends section, and overall financial comparisons in the Profitability section. Summary findings in both areas are as follows:

Petroleum Industry Trends

California, Arizona and Nevada

- California, as well as Arizona and Nevada, will continue to be highly dependent on imported products to meet increasing demands for gasoline. Import dependence (net of any exports) will increase for gasoline from 18.3 percent in 2005 to 22.1 percent in 2012, an increase of about 82 thousand barrels per day (TBD). Total imports (finished gasoline and components, ethanol) will increase from 267 TBD in 2005 to 349 TBD in 2012. About half of this growth can be met by increased supply from Texas on the recently expanded Kinder Morgan East Line. Marine imports would increase about 52 TBD, offset by about 12 TBD from decreasing need to import ethanol as California ethanol production increases.

- High growth rates for distillate fuel (diesel) demand will result in net import requirements increasing from 29 TBD in 2005, or 8 percent of demand, to 80 TBD, or 19 percent of demand in 2012. Again, the Kinder Morgan East Line could mitigate some of this import requirement.

- High growth rates for jet fuel demand will result in net import requirements increasing from 80 TBD, or 22 percent of demand in 2005, to 153 TBD, or 35 percent of demand in 2012. This is a large dependency, and even though, the Kinder Morgan East Line could mitigate some of this import requirement, much of the volume will need to be marine deliveries.

- Crude Oil import dependency (foreign plus Alaskan North Slope) increases from 60% of crude supply to 67% over the period from 2005 to 2012. This is an increase of 180 TBD crude imports based on additional refining crude capacity growth and declining California production.

- Refinery capacity growth in California has lagged the rest of the United States and the world. The outlook for 2005 through 2012 indicates, based on announcements of specific refinery expansions, that this trend will be sustained.

- Barriers to refinery expansions in California exist despite much higher operating margins than the rest of the United States. These barriers include 1) environmental offset requirements for new capacity; 2) long, complicated and uncertain permitting process from multiple entities; 3) actions being proposed or implemented by port authorities to reduce/eliminate/relocate oil import/export tankage and terminals; 4) significantly more stringent product specifications in California versus the U.S. overall; and, 5) sustained higher cost of operating a refinery in California.

- Increased exposure to the high cost of shipping on Jones Act vessels from the Gulf Coast to California. The higher gasoline marine import requirements may, in large measure, be supplied as components or possibly finished CARBOB gasoline from Gulf Coast refiners. Jones Act vessel freight rates have spiraled up in the past several years as the fleet is gradually being retired. The increased gasoline import requirements for California are occurring at a time when transportation tonnage is declining.

- Extended periods of significantly higher California CARBOB prices than Gulf Coast RBOB or conventional gasoline prices have resulted in increased shipments into California. However, these price spreads have not enticed traders, Gulf Coast refiners, or Caribbean or Canadian refiners to substantially alter their production to sustain these movements. This may be because of difficulties in producing the California grades, and/or the concerns of shippers on limited port capability on the West Coast (dock, storage, and transshipment infrastructure).

- The net implications of the above findings are that California's petroleum product supply chain, in particular gasoline and jet fuel, will continue to be a fragile system prone to disruption and resultant price escalations. The tight market and distant supply alternatives will sustain California gasoline prices, as well as diesel and jet fuel, at price levels well above the U.S. markets east of the Rockies.

United States

The outlook for petroleum product supply in the U.S. is markedly different than California. Overall demands are expected to grow by 1.5 percent annually for gasoline, and 1.4 and 2.9 percent annually for distillate and jet fuel (compared to 1.7 percent for gasoline, 2.6 percent for distillate, and 3.5 percent for jet fuel for the three state region)

Refinery capacity will grow at a higher pace than in California, as major expansion projects will be implemented by Motiva, ConocoPhillips, and Marathon, along with smaller projects from other refiners. In addition, supply for fuel products will be bolstered by significant growth in domestic ethanol production. The implications of these trends are noted below:

- The additional demands forecast for gasoline will be more than offset by increased refinery production and ethanol penetration into the gasoline pool. Gasoline import levels should decline from a peak of 1,230 TBD in 2006 to 734 TBD in 2012.

- The forecast assumes that refinery utilizations will be restored to levels seen in 2000-2004 (averaging 92 percent) by 2008. Utilization in 2006 is estimated at 88 percent, rising to 91 percent in 2007.

- Ethanol production will continue to grow rapidly, increasing to the 2012 Renewable Fuel Standard (RFS) of 7.5 billion gallons per year (bgy) by early 2008. This volume is about 489 TBD. Additional ethanol production projects that will *more than double this number* are targeted for completion by the end of 2009.

  This growth rate likely will not materialize in such a short time frame given bottlenecks in the construction industry; however, this study assumes that by 2012 the ethanol production capacity in the U.S. will grow ratably (at a consistent annual pace) from 2008 at about 1.5 bgy to be at an average production of 14 bgy (915 TBD) in 2012.

- The ethanol growth is assumed to be directly used in the gasoline pool, either from economics (as ethanol production increases above mandated market area demands), expansion of E-85 sales, or further government mandates.

- Distillate imports decline very slightly over the period, as additional refinery production from higher utilization and capacity expansions more than offsets strong diesel demand growth.

- Jet fuel imports increase from about 146 TBD in 2005 to 301 TBD in 2012 as higher jet demand more than offsets refinery production growth. Note that most of this increase is in fact into the California-Arizona-Nevada market.

- The higher influx of gasoline supply into the U.S. market from internal growth (refinery production plus ethanol) will, as noted, reduce import requirements into the East Coast market. At the same time, continued trends toward dieselization in Europe will push surplus European gasoline and components into the U.S. market. Major refineries in Eastern Canada (Irving Oil) and in the Caribbean (Hess and others) will continue to push imports into the U.S. The net result could be a lower refining margin for U.S. refineries in the East of the Rockies markets.

- The implication for California is that there may be greater incentive for refiners currently supplying the East Coast (domestic and foreign) to find ways to increase production of California grade gasoline. If produced, volume could be transported via tanker or directly from the Gulf Coast through Longhorn pipeline into Arizona (backing gasoline into California). In addition, non-refiner shippers, such as airlines, may find opportunities in moving jet fuel volume on Longhorn pipeline into the Phoenix and Tucson markets.

Refinery Findings

- The United States refineries are the most sophisticated in the world, with significantly higher level of clean product (gasoline, jet, and diesel) yield than world refineries, despite a raw material supply including some of the highest sulfur-bearing, heaviest API gravity crudes in the world. California refineries have an even higher level of sophistication than the U.S. average.

- Both California and U.S. refineries aggressively push the refinery utilization to maximize crude processing. The impact of the 2005 hurricanes is having a clear impact on 2005 and 2006 utilizations for Gulf Coast refineries.

- California refineries have significantly higher capability to upgrade heavy residual fuel oil into gasoline than the U.S. average. Refiners outside California have spent (and will spend) significant capital to expand capacity to upgrade residual fuel, and to hydro treat gas oil stocks to increase flexibility to refine heavier and less expensive crude oil.

- Relative refinery margins between the West Coast and the Gulf Coast have exhibited a consistent annual spread reflecting a tighter market on the West Coast. Refinery utilization levels (apart from hurricane incidents) appear consistently high on an annual basis regardless of the absolute refining margin. (Seasonal utilization levels reflect annual refinery maintenance periods in the first and fourth quarters). Utilizations for secondary process units have been enhanced by increased unfinished imports over the last several years for the U.S. and California.

Potential Considerations to Improve Supply

The issues which are impacting fuel supply and prices in California appear to be driven by a fragile supply chain, aggravated by long and time-consuming replenishment alternatives, complex gasoline quality requirements for parties wishing to enter or supply the market, lengthy permitting process for infrastructure improvements, and pressure to reduce or relocate tankage that is essential to the continuous supply of fuel products to California consumers.

Possible opportunity areas which would work to improve supply chain stability include:

Organize to Achieve Results. Recommendations in the past to protect or improve the supply infrastructure, permitting processes, and so on have, in large measure, not been successful. Consequently, a key recommendation is to provide a process to track progress on an ongoing basis, with reporting to the Governor, Legislature and public on a regular basis. Ideally this would be via an independent entity such as the Energy Commission. The recommendations below will require leadership and consensus on difficult tradeoffs to make progress, and there must be accountability for actions to address the issues on a priority basis.

Don't harm the current oil import and distribution infrastructure. Actions should be taken immediately to freeze any project or action which would result in the closure or relocation of petroleum distribution assets, until a thorough assessment of the impact on petroleum supply can be established.

Implement recommended changes to streamline the permitting process. Over the past few years, several studies have been done by the Energy Commission, and Consultants to the Commission to evaluate methods to improve and streamline the permitting process. Numerous recommendations have been proposed. Little has been implemented despite evidence from the oil industry that permitting processes have had a significant effect on the progression of refinery and infrastructure projects. These recommendations should be validated and implemented.

Evaluate and Implement Modifications to Gasoline Quality Specifications
Provide flexibility for refiners or traders to import gasoline into California at RBOB quality levels, with a penalty, to improve supply alternatives and streamline infrastructure requirements (less component blending ties up less tankage).

Implement an aggressive program to market E-85 in California. The existing ethanol supply chain, growth in U.S. ethanol production, and base import levels of gasoline and components in California are significant drivers to consider how to ramp up E-85 as an automotive fuel in the state. An initial goal could be an assessment of the environmental impact, auto industry position, and logistics needs within six months. One gallon of E-85 usage would reduce gasoline need by about 0.75 gallons due to the lower BTU content of E-85.

Create Incentives to Exploit Potential Changes in Supply and Demand East of the Rockies (EOR). The expansion of the Kinder Morgan East Line, availability of the Longhorn pipeline from Houston to El Paso, and the potential reduction in import requirements on the East Coast could create significant opportunity to increase supply into the three-state region from Texas. This supply route relieves port issues and enhances supply flexibility. Ability of California to influence this initiative may be limited, but market forces may drive this regardless.

Oil Company Profitability

This section of the report includes an assessment of U.S. refiner financial performance and a comparison with other capital and non-capital intensive manufacturing industries during the 1995-2005 time period. ICFI also evaluated the historical trends for the major integrated oil companies and U.S. refiners against each other. Finally, ICFI will provide comments on the objectivity of a report developed by Ernst and Young for the American Petroleum Institute (API) on how companies utilized their profits.

Key findings include:

- Petroleum refining companies earn about 1.8 cents per dollar of sales more than other manufacturing companies based on U.S. Census Bureau data; however, the earnings on a ROCE (Return on Capital Employed) basis show that petroleum refining has an ROCE very similar to the overall manufacturing sector over the study period.

- Comparison with Census Bureau data for other capital intensive industries shows that petroleum refining companies' average ROCE is consistent with other key sectors (chemicals, primary metals, paper). Comparison with non-capital intensive industries shows a similar consistency, with several comparative industries performing significantly better.

- Evaluation of profitability for the integrated majors and domestic refiners over the study period shows significant volatility of earnings. The volatility mirrors the key performance indicators of crude oil price and refining margins. In periods of global recession (e.g. the 1998-99 Asian recession; the period in 2002 following the events of September 11, 2001) both crude prices and refining margins fell, significantly impacting ROCE. In 2004 to the present, higher global demands for oil and tight refinery capacity have resulted in the highest ROCE performance over the study period.

- These market-based events (recessions, high global demand periods, etc.) were not orchestrated by the integrated oil companies or the domestic refiners. However, the petroleum refining companies and their investors see the benefits of higher prices and margins, as well as the impact of low prices and margins.

- The trend of ROCE over the study period for the integrated major oil companies indicates that each of the largest companies (ExxonMobil, BP, Shell, Chevron and ConocoPhillips) experience almost identical hills and valleys in the ROCE performance that mirror market changes. Nonetheless, the spread of performance between the "highest" and "lowest" ROCE in any given period for this grouping indicates that there can be variability in results of 5-10 percent ROCE between the best and poorest performing company.

- The Ernst and Young report on how oil companies utilize their profits was developed with public information by a very reputable firm. It appears to be a straightforward application of the public financial data into a cogent analysis of the industry's use of capital.

TASK 1. MARKET TRENDS AND OUTLOOK FOR REFINED PRODUCT SUPPLY IN CALIFORNIA AND THE U.S.

Introduction and Objectives

Over the past ten years the global oil markets have changed significantly. New demands have emerged from continued growth in economies worldwide, particularly in Asia, and sustained growth in transportation fuels in all global markets. These changes have occurred at the same time as many countries and regions have implemented fuel specification changes designed to improve the environment, and at the same time as bio-fuels are becoming a greater factor in substitution for fossil-based fuels.

In recognition of these factors, and the fact that the California market has continued to experience supply and price disruptions that have impacted consumers and businesses, the Energy Commission requested an assessment of the state of the industry in the U.S. and California, and a forward outlook. Therefore, the objective of this task is to identify how the petroleum industry refining sector, demands, and supply have changed over the past ten years in California, the U.S. and the world. In addition, a key objective is to identify the outlook for California from the current period through 2012 for refining capability, demands, and supply in the context of the overall U.S. and global outlooks.

In addition, ICFI will review and discuss key issues which have, or potentially could have, an impact on California markets, and recommend possible areas in which the Energy Commission may take steps to mitigate future supply and price disruptions.

The specific areas which will be investigated are summarized in the Task definition from the Energy Commission:

In this task, contractor will provide a description and assessment of the economic efficiency of California's refining market. ICF will examine petroleum market trends in California over the last 10 years. This will include examining refining trends, product demand trends, product import and export trends, changes in inventory management, and an examination of the impacts of seasonality on market factors. ICF will also identify key factors that contribute, or may potentially contribute, to supply constraints or disruptions in refined product deliverability. Finally, contractor will develop options to consider that have the potential to mitigate these supply constraints and price volatility. The trend assessment should include at a minimum the following:

Subtask 1.1: ICF will analyze petroleum industry trends for California, versus the rest of the United States and the rest of the world, over the last 10 years (1995 through 2005). This analysis will include, but not necessarily be limited to:

- *Refining*
    - *Number of Operating Refineries*
    - *Refining Distillation Capacity*
    - *Utilization Rates (U.S. Refineries)*
    - *Refinery Complexity*
    - *Output and Yield of Petroleum Products by Category (gasoline, diesel fuel, jet fuel, residual fuel oil, and other)*
- *Product Demands: Gasoline, Diesel fuel, Jet fuel, and Residual*
- *Product Import and Exports (including into Arizona and Nevada)*
- *Stock levels for key products (Gasoline, Diesel, Jet Fuel, and Residual Fuel)*
- *Dependence on Imported Crude and Refined Products*
- *Freight Rates for Clean Tankers*

Subtask 1.2: ICF will analyze the petroleum industry market outlook for California from 2006 to 2012 versus the rest of the United States. This analysis will include, but not necessarily be limited to:

- *Announced refinery capacity expansions (U.S.)*
- *Announced and planned ethanol facilities*
- *Forecast demand growth in U.S. (EIA) and California (Energy Commission)*
- *Estimate increased or decreased product import requirements*
- *Compare California's fuels supply outlook versus today*

Subtask 1.3: ICF will identify key factors which have contributed to, or may contribute to supply constraints or disruptions in the California markets, and comment on their sustainability in the future.

Subtask 1.4: ICF will develop three to five specific options for the Energy Commission staff to consider that have the potential to mitigate the market volatility and supply disruptions in California. ICF will discuss the potential cost and feasibility of each, as well as "pros" and "cons" for the market.

1.1 Petroleum Industry Trends

1.1.1 Refining

The past 30 years have seen significant periods of transition in the U.S. refining industry. The period from 1973 to 1981 was marked by U.S. government attempts to regulate the oil market. In 1973 the U.S. Government responded to the Arab Oil Embargo of 1973 by introducing the Emergency Petroleum Allocation Act (EPCA) which, among other measures, favored small inefficient refineries and made them profitable. This led to a large increase in the number of domestic refineries, increasing from 281 in 1973 to 324 in 1981[1]. By 1981, the U.S. Government had removed essentially all price and allocation controls on the oil industry. This brought the refining industry back into a competitive marketplace and precipitated a number of actions by refiners.

By 1985, the number of refineries had fallen to 223, with 24 of those refineries idle (not operational). Total refinery capacity in 1985 was 15,700 TBD, and operating capacity was 14,400 TBD. The refining business however was still not performing well in the eyes of investors. The overhang of idle capacity, relatively small refineries, weak refining crack spreads (the spread between product prices and crude costs), and high operating costs was apparent, and the industry needed to further reduce costs and increase margins. At the same time, there was increased pressure on the industry to meet tougher environmental standards in both fuels and in stationary source emissions which required capital investment. These collective factors forced refiners to make difficult decisions on cost and capital management to boost their financial viability.

The decisions made to improve financial performance covered a wide area of effort. One of the primary decisions was to take a hard look at each refinery to evaluate its long term financial viability given the capital expenditure needed for environmental controls, the refineries' performance and cost structure, and supply alternatives for customers in the refinery's market area. Moreover, increased demands for light ends and tougher environmental standards brought technical innovations. The new technology had greater economies of scale and better yields which went against small refiners. Small refineries without a strategic location advantage could be shutdown, saving all the fixed costs (labor, etc) and future capital requirements, with larger, more efficient refineries increasing utilization or adding capacity to provide similar volume of product at lower cost.

This level of focused assessment has been ongoing since the mid-1980s. As the study period for this analysis covers the 1995-2012 timeframe, a great deal of the rationalization and cost reduction in the industry from the mid-1980's had already been done. Despite those changes, U.S. refinery margins remained weak, making decisions for any large scale refinery expansions imprudent and difficult to rationalize to investors. Refinery investment strategy since the mid-1990's has focused on projects to meet increasingly stringent sulfur specifications in fuels (gasoline and on-road diesel), increase reliability and upgrading capability to process heavier and more sour crudes, and reduce energy and other operational costs. Capacity expansions have been, for the most part, small, low cost expansions of equipment at existing refinery sites.

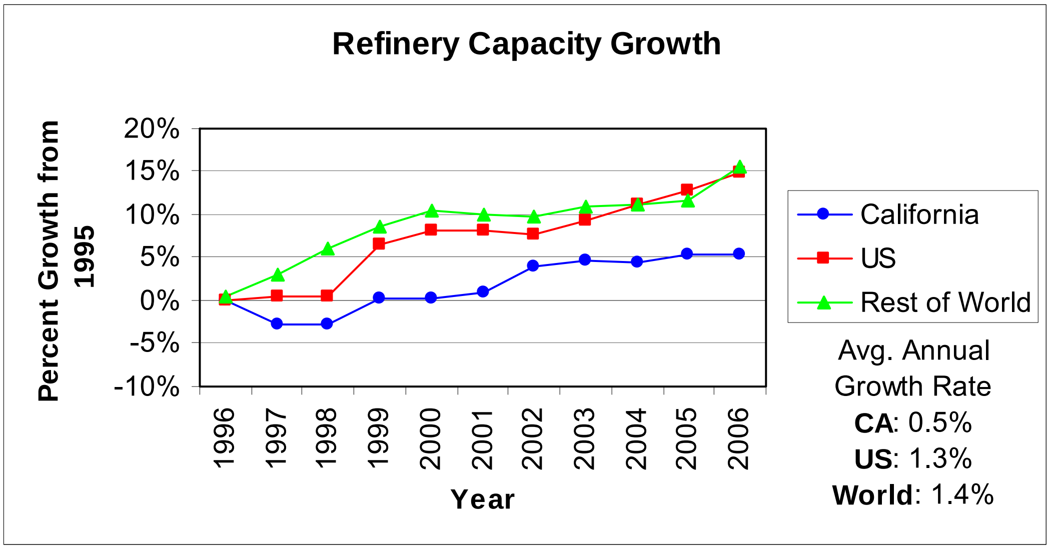
In this section, key aspects of the refining industry will be examined for California, the United States[2], and worldwide over the past ten years since the mid-1990's, including:

- Capacity and Numbers of Refineries
- Complexity and Upgrading
- Utilization
- Yields

Refinery Capacity Trends

Refinery capacity has increased significantly in the United States and worldwide (See Exhibit 1), with global refinery capacity, and U.S. capacity rising about 15 percent each from 1995 to January 2006. The capacity growth has primarily been through expansions of existing refinery capacity, with no new grass roots refineries[3] completed in the United States since Marathon's refinery in Garyville, Louisiana in 1976.

Exhibit 1. Crude Capacity Growth Rate, 1995 to 2006, Percent vs. 1995



Sources: EIA Petroleum Supply Annual and EIA Refinery Capacity Report.
Note that the EIA did not collect data for the years 1996 and 1998. The refinery counts and capacity for 1996 and 1998 have been estimated using the previous year's data. This estimate was used in all related Exhibits showing 1996 and 1998 capacities.

While the capacity growth for the U.S. and world has been strong, capacity growth in California has been significantly less, with a total capacity increase of only 5 percent over the same period. Exhibit 2 shows results in tabular format.

Exhibit 2. Crude Capacity Growth, 1995 to 2005, TBD

	California	U.S.	Rest of World
1995	1,902	15,082	58,848
1996	1,902	15,082	59,097
1997	1,851	15,168	60,634
1998	1,851	15,168	62,418
1999	1,906	16,061	63,887
2000	1,905	16,315	65,009
2001	1,919	16,320	64,713
2002	1,978	16,246	64,602
2003	1,990	16,484	65,254
2004	1,984	16,759	65,356
2005	2,005	17,006	65,634
2006	2,005	17,317	68,001
Growth	103	2,236	9,153

Sources: EIA Petroleum Supply Annual. EIA Refinery Capacity Report, and Oil and Gas Journal. Worldwide Refining Survey

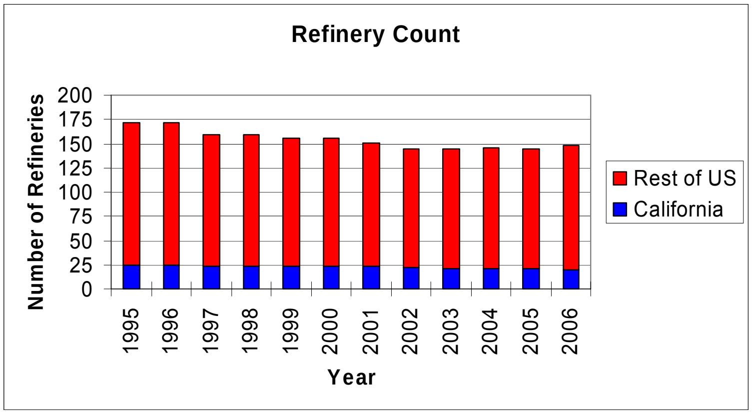
The slowdown in capacity expansion in California has occurred despite much stronger historical margins for refining than in the rest of the United States. The same refiners who have expanded somewhat in the Gulf Coast (where margins have been lower) have been hesitant to expand in California. The specific rationale or perspective that each refiner may have can be very different; however there appear to be some fundamental factors which may directly influence decisions re California expansion projects versus the rest of the U.S.:

- The time and effort required to design, engineer and build, modify, or shutdown equipment to provide environmental offsets is a significant cost above the desired process unit configuration(s) under consideration.
- The permitting process can be difficult and time-consuming. This can unduly extend the time required to build the project (impacting return on investment), and in fact put project development monies at risk if the approval is not secured.
- The ability to expand implicitly assumes that incremental supply of crude oil and other feedstocks to fill the expanded capacity will, with certainty, be able to be physically imported. The actions being considered and/or proposed by Port Authorities in Southern California have policies and initiatives that focus on eliminating existing marine infrastructure and preventing the addition of new/expanded/upgraded petroleum infrastructure facilities. These issues would raise serious concerns to any refining investor about assurance that the additional capacity can be supplied.
- Incremental products must meet all prevailing California product specifications (CARBOB gasoline and CARB Diesel), which requires more investment dollars per barrel of capacity than expansions in other markets

In general, refiners appear to see California as a high cost area with high risk that regulatory requirements, permitting issues, and infrastructure changes can significantly undermine investment returns.

Over the period from 1995, there has been a reduction in the number of operational refineries in the United States. Exhibit 3 shows the number of refineries declining from 171 to 148 over the study period, and California refineries declining from 25 to 21. Worldwide, the number of refineries peaked in 2000 at 757 and has declined to 679 since then.

Exhibit 3. U.S. and California Operable Refinery Trend



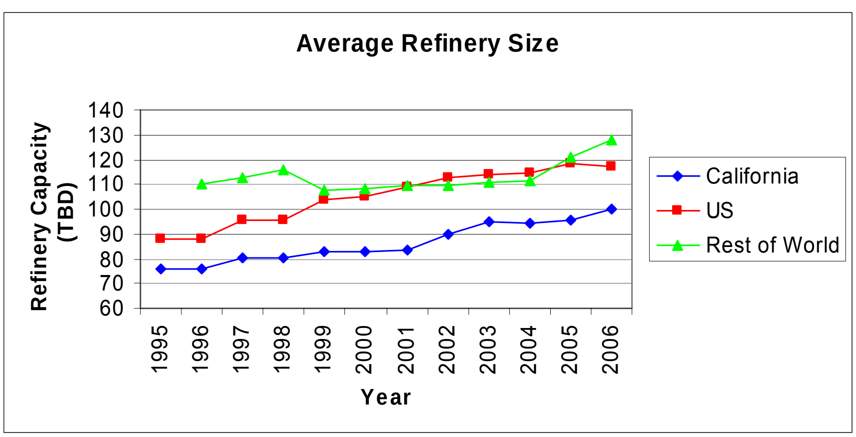
Sources: EIA Petroleum Supply Annual and EIA Refinery Capacity Report.

Refineries that have shutdown in California since 1995 are as follows:

- Powerine Oil Company, Santa Fe Springs, 46.5 TBD – Shutdown Sept. 1995
- Sunland Refining Corporation, Bakersfield, 12 TBD – Shutdown Dec. 1995
- Pacific Refining Company, Hercules, 50 TBD – Shutdown Sept. 1997
- Tricor Refining LLC, Bakersfield, 11 TBD (Vacuum) – Shutdown Jan. 2002

Refinery closures and continued capacity growth have caused the average refinery size globally and in the U.S. and California to increase as seen in Exhibit 4.

Exhibit 4. Average Refinery Size, TBD



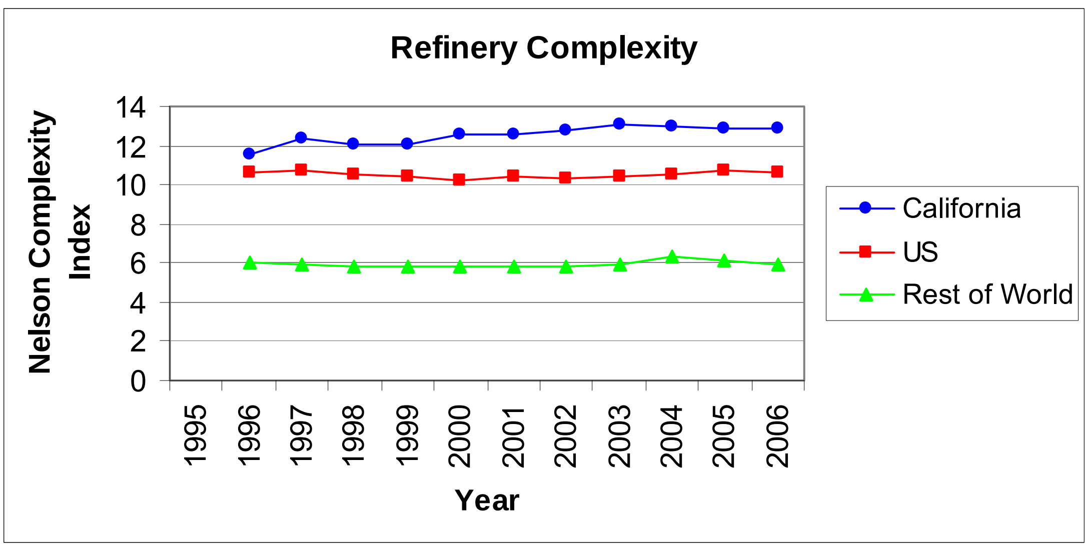
Sources: EIA Petroleum Supply Annual. EIA Refinery Capacity Report, and Oil and Gas Journal. Worldwide Refining Survey.

Complexity and Upgrading

Complexity is a measure of the degree of refining processes used within a refinery to convert crude oil into a range of products. Refineries with low complexity usually have few processing units other than crude oil distillation, and will produce much lower yield of clean products (gasoline and distillate fuels), and more residual fuel as compared to more complex refineries. Complexity can also be an indicator of relative investment levels for refinery construction costs, as well as fixed and variable operating costs. Complexity is measured by the "Nelson Complexity Factor", which evaluates complexity based on process configuration, size, multiple number of units, etc.

In general, larger refineries tend to be more complex as they can have multiple units of the same type (e.g. two reformers, two fluid crackers, etc), and are more likely to have petrochemical integration or lube oil processing. Exhibit 5 shows the trend in refinery complexity for California, the U.S., and the world over the study period.

Exhibit 5. Average Refinery Complexity Factor



Source: Oil and Gas Journal Worldwide Refining Survey

It is noteworthy that California has a much higher average complexity than the U.S. overall and more than double the complexity of the average global refinery, despite having smaller average refinery capacity. This is because California refineries process extremely low gravity (15-20 API) crude oil, which requires very high residual upgrading, and requirements for fuel quality and refinery emissions in California necessitate substantial hydroprocessing capability. Strong demands for fuel products in California require a high conversion[4] level in refineries, which also increases complexity.

In fact, Exhibit 6 shows that California has six of the ten most complex refineries in the United States. The California complexity is driven by the intensity of the refinery processing hardware, including significant high pressure hydrotreating and residual upgrading to maximize the yield of clean products from heavy and highly contaminated crude (high nitrogen levels, metals, etc). Although California refineries have high complexity, they have less capacity than Gulf Coast and Midwest refineries for processing higher sulfur crudes, with only two refineries ranked in the top 20 in the U.S. in sulfur processing capacity[5]. This is because California refineries have been configured to process local California and Alaska North Slope (ANS) crudes, which have lower sulfur (1 percent sulfur range) than the Mexican, Venezuelan, and Canadian crudes that are predominant imports in PADDs 2 and 3. This fact mitigates to some degree California's ability to process higher sulfur imported crude such as Mexican Maya and higher sulfur Middle East crudes.

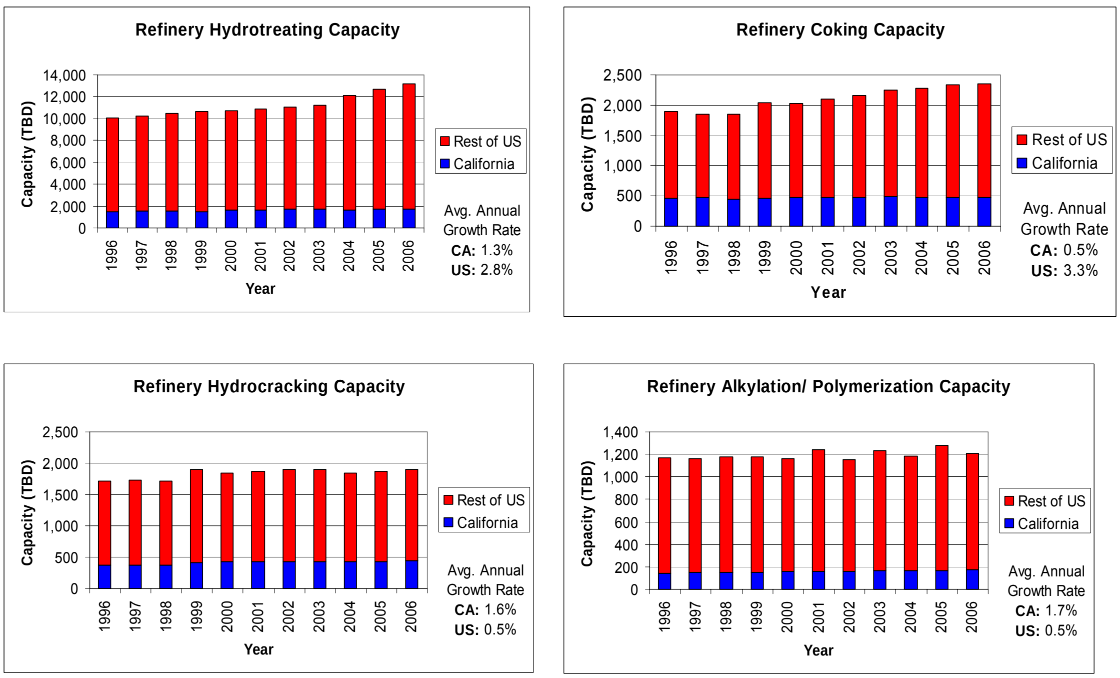
Exhibit 6. Highest Complexity U.S. Refineries

State	Company	Site	Atmospheric Distillation, BPD	Nelson Complexity Index
California	Valero Energy Corp.	Wilmington	80,000	18.1
Texas	Valero Energy Corp.	Corpus Christi	205,000	16.9
Texas	Motiva Enterprises LLC	Port Arthur	285,000	16.7
California	Chevron Corp.	Richmond	225,000	16.5
California	Shell Oil Products US	Wilmington	100,000	16.4
California	Shell Oil Products US	Martinez	157,600	15.3
Texas	Valero Energy Corp.	Three Rivers	96,000	15.2
California	ExxonMobil	Torrance	149,500	14.8
Kansas	National Cooperative (NCRA)	McPherson	82,200	14.7
California	ConocoPhillips	Los Angeles	138,700	14.6

Source: Oil and Gas Journal Worldwide Refining Survey

For refinery upgrading, ICFI compared trends over the study period for key secondary unit[6] upgrading capacity for both the U.S. and California. Specifically, ICFI compared trends for coking, hydrotreating, hydrocracking, and alkylation capacity. These areas are critical secondary units required for refiners to process higher sulfur and heavier crude oils, reduce sulfur levels in gasoline and diesel fuel, and improve ability to meet California and Federal gasoline specifications. Exhibit 7 shows the capacity trends for California and the U.S. in these categories.

Exhibit 7. Key Upgrading Capacity Trends, U.S. and California



Source: Oil and Gas Journal Worldwide Refining Survey

The above charts indicate that for coking capacity and hydrotreating capacity, the U.S. growth rate has outpaced California refiners over the past ten years. For coking, this is primarily because California had already established a very high coking capacity as a percent of crude run due to the heavy California crude being processed in the state. The rest of the U.S. was well behind California in residual[7] upgrading capacity, and increased imports of heavy, sour crudes into PADDs 1, 2 and 3 provided sufficient incentive for capacity expansion. The increase in hydrotreating occurred partly for the same reason (i.e. higher sulfur crude processing in PADDs 1, 2 and 3) and also because requirements to lower sulfur levels in both gasoline and diesel fuels impacted both California and other PADDs.

Overall, in both California and the U.S, growth in coking and hydrotreating upgrading capacity outpaced growth in overall crude processing capacity. This indicates clearly that refiners have been focused on investing to run heavier, lower cost crude, improve yields, and meet improved product quality requirements rather than on expansion.

California capacity grew more rapidly than the U.S. in areas of hydrocracking and alkylation. Hydrocracking is a very high pressure process to upgrade unfinished cracked gas oils into jet fuel, naphtha, or diesel fuel. Alkylation is a process by which olefins and isobutane are taken together to produce a very high octane, sulfur-free gasoline blending component that is a key ingredient in producing California's CARBOB product.

Exhibit 8 shows the relative difference in quality between CARBOB (California Reformulated Gasoline prior to adding Ethanol), RBOB (Federal Reformulated Gasoline prior to adding Ethanol), and conventional gasoline. The lower vapor pressure, lower aromatics, and tighter distillation specifications require significant changes by Gulf Coast refiners to produce CARBOB product on specification.

Exhibit 8. Gasoline Specification Comparison

Specification		Conventional	CARBOB	RBOB @10%
Octane (R+M)/2	min	87	85	83.7
RVP	summer	7	5.99	7.2
Distillation (ºF)	50% Evap max	250	232	250
Distillation (ºF)	90% Evap max	374	335	374
Sulfur (ppmwt)	max	80	32	80
Benzene (vol %)	max	4.9	1.22	1.3
Aromatics (vol %)	max		38.7	50

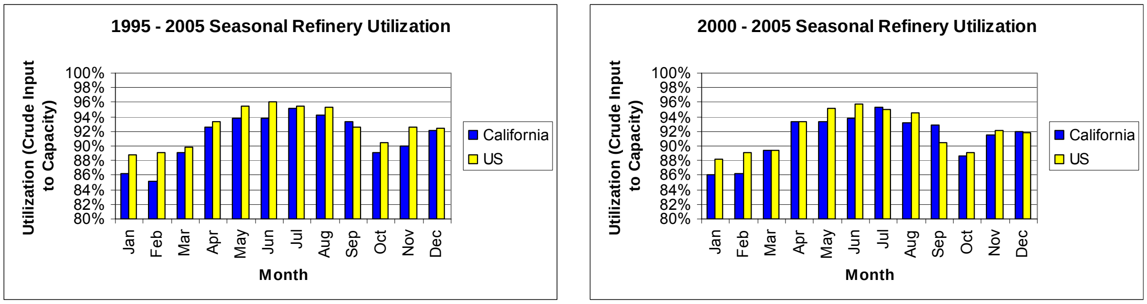
Source: Kinder Morgan www.kindermorgan.com, Colonial Pipeline www.colpipe.com.

Refinery Utilization

Refinery utilization is a measurement of the degree that refinery crude unit capacity is filled with crude oil and other inputs. The ability of a refiner to process crude oil is limited by several factors. One is the sheer physical limits on the amount of crude oil that can be pumped, heated and boiled (distilled), and segregated into different boiling fractions for further refinement. Second is the capacity of processing units downstream of the crude unit to convert the different boiling fractions into gasoline or distillate blending stocks, or stocks for further refining. Third, access to ratable[8] crude oil supplies and ability to move products out of the refinery on a continuous basis is essential. The tankage at the refinery for the multiple feedstock and product streams is limited, and can significantly restrict refinery throughput during periods of operational disruptions or planned maintenance.

Exhibit 9 shows the general pattern of refinery utilization in the United States and California. There is clearly a seasonal trend that is consistent every year. Refinery utilization is lower in the first quarter and fourth quarter of each year. Refineries operate equipment at extremely high temperatures and pressure that are pumping, compressing, boiling, and catalyzing a wide range of hydrocarbons that are extremely volatile. The equipment must be maintained on a timely schedule to take care of wear and tear and ensure the highest degree of safety for personnel and reliability for operations. The maintenance periods (turnarounds) typically occur in the first and fourth quarters when overall gasoline demands are lowest.

Exhibit 9. Refinery Utilization Seasonality 1995-2005 and 2000-2005

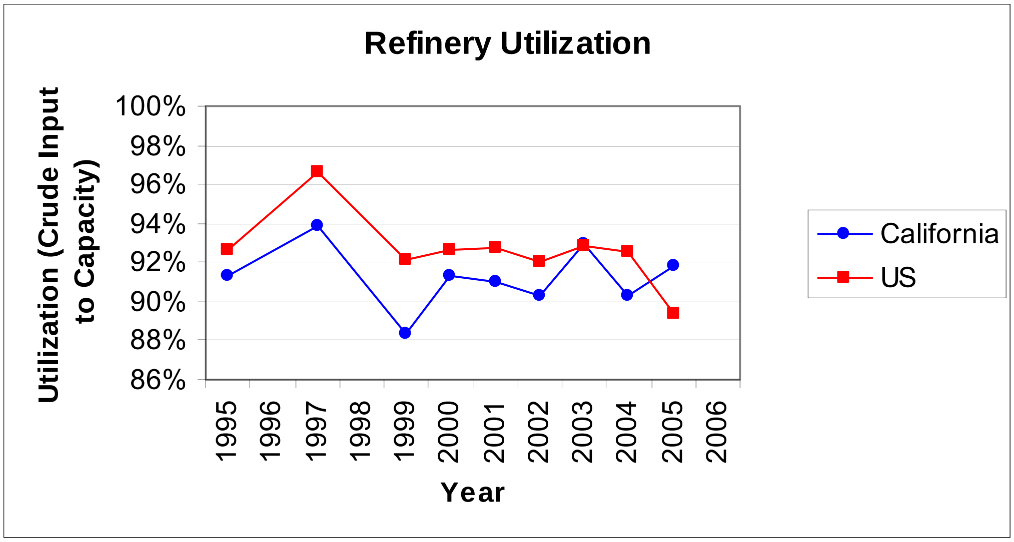


Sources: EIA Petroleum Supply Annual. EIA Refinery Capacity Report

Crude runs are reduced during turnarounds because of crude unit maintenance, and also during secondary unit maintenance. Refinery planners must manage crude throughput to limits of tankage for secondary unit feedstocks (naphtha, gas oil, etc), recognizing the capacity limits of the secondary units to “run off” the inventory build up after the unit is back in operation.

Exhibit 10 shows the historical refinery utilization for the total U.S. and for California over the study period. California utilizations tend to be 1-2 percent below the U.S. average. In general, the lower California utilizations indicate less flexibility to manage turnarounds than refineries in PADDs 1-4. In the Gulf Coast, for example, planned turnarounds of secondary processing units, or unplanned shutdowns of these units, can be managed at times with less reduction in crude runs due to an active market for the unfinished feedstocks (naphtha, gas oil, etc). A refiner with a turnaround or operational problem can sell surplus gas oil (for example) to another refiner, or move it to one of his other refineries relatively easily compared to California. Movements of feedstocks and product by barge or vessel are much more easily accomplished due to far more extensive waterway system and vessel availability than in California.

Exhibit 10. Historical U.S. and California Refinery Utilization



Sources: EIA Petroleum Supply Annual. EIA Refinery Capacity Report

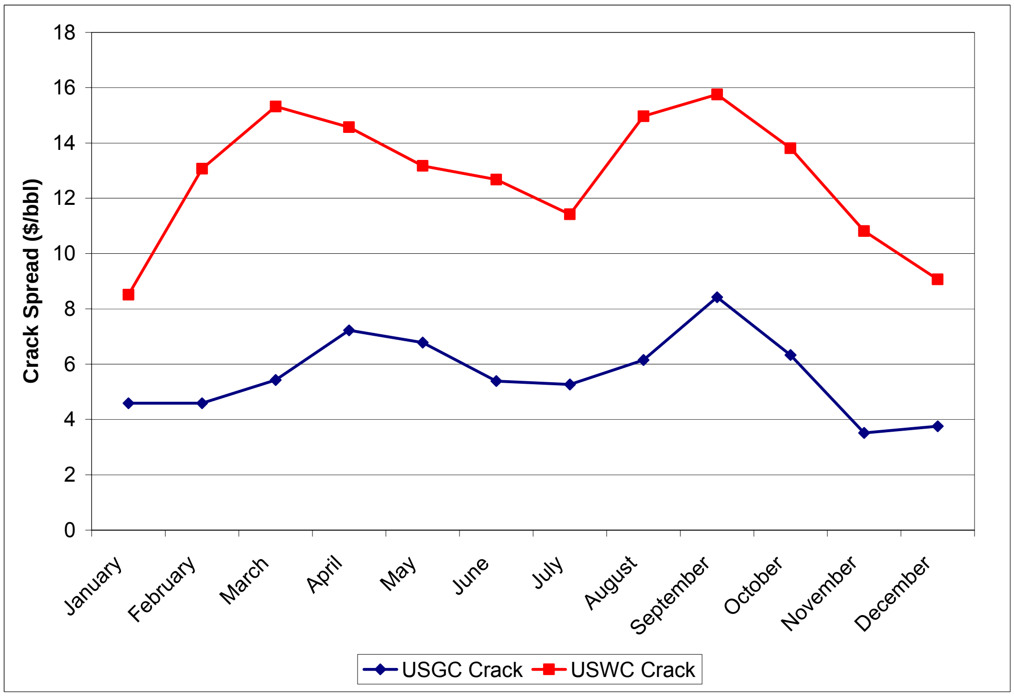
An additional factor in the utilization difference is the greater complexity of refinery operations in California indicated earlier in Exhibit 6. The higher severity of the operation necessary due to the characteristics of California crudes, and the need to meet stringent product specifications requires very careful management of turnaround timing as well as making the process equipment more prone to reliability problems. However, in 2005, California utilization exceeded the U.S. overall due to the severe impact of Katrina and Rita on the PADD 2 and 3 refining operation, and in fact has been averaging within a percent of the U.S. overall since 2000, at 91.3 percent utilization.

Recognizing the seasonal pattern of utilization shown in Exhibit 9, a further analysis was done to identify if there was a pattern to the level of utilization and refinery margins, which is the difference between the price of refined products from a refinery and the cost of the crude oil used to yield the gasoline and diesel fuels. Refinery margins were measured by the West Texas Intermediate (WTI) 3-2-1 crack spread[9] for PADDs 1-4, and the Alaskan North Slope (ANS) 3-2-1 crack spread for the West Coast.

Exhibit 11 shows the level of crack spreads on a monthly average basis for both WTI and ANS over the past six years. In general, margins do follow a seasonality pattern. Margins are lower in the winter and tend to be higher March through October, with the pattern being similar on both the West Coast and Gulf Coast. The margin itself tends to be higher in the March-October period since that is when gasoline is typically at a premium to distillate (and gasoline has twice the impact on the factor). The low refinery utilizations in the first quarter reflect turnarounds that tend to reduce supply and thereby put upward pressure on margins heading into the gasoline season.

West Coast margins on average are double Gulf Coast margins. The absolute level of margin is a function of each region's overall supply and demand balance, and is indicative of the tight product market on the West Coast. For utilization purposes, the important takeaway is that refiners appear to be working to maximize utilizations in both regions despite some significant margin differences between regions and seasons.

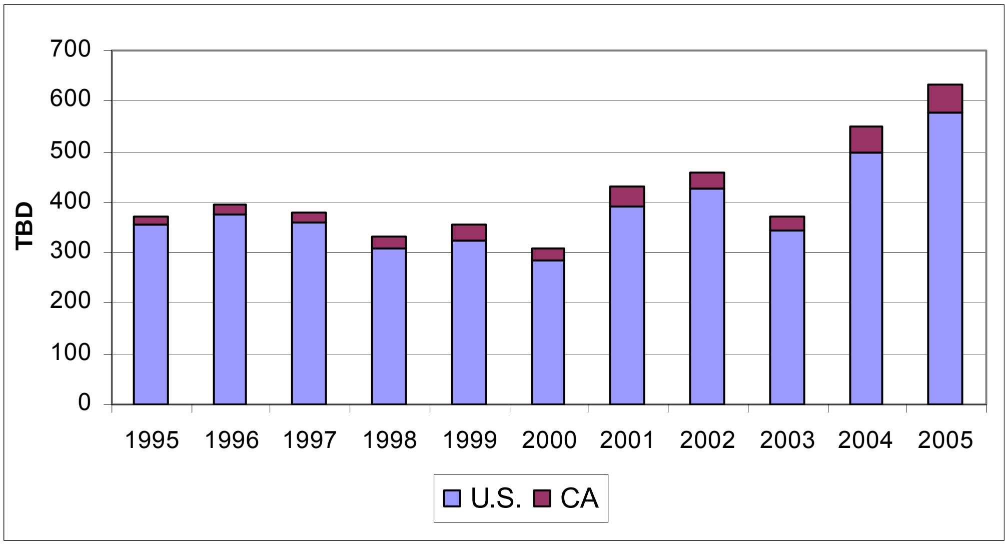
Exhibit 11. Historical U.S. and California Seasonal Crack Spreads, 2000-2005 ($/BBL)



Sources: Platt's OilGram Pricing History

As a final consideration on utilization, U.S. refiners have been increasing the volumes of unfinished feedstocks[10] processed since 2000. Exhibit 12 shows the level of unfinished imports into the U.S. and California over the study period. This increase is driven by relative prices of the feedstock in its source area (for example, Europe), freight costs, and the value in the U.S. market of the refined products from processing. These opportunistic actions provide greater capacity utilization of gasoline and distillate producing equipment in the refinery.

Exhibit 12. U.S. & California Total Unfinished Imports, TBD



Sources: EIA Petroleum Supply Annual. EIA Refinery Capacity Report

Refinery Yield Comparisons

The yields of petroleum products from a refinery are highly dependent upon the configuration and complexity of the refinery, and the types of crude oils processed. As seen on Exhibit 5, California and the United States have refineries with a much higher complexity than the rest of the world. Consequently, the United States can process heavier and higher sulfur crudes and can upgrade those crudes into a much higher percentage of gasoline and distillate fuel than the rest of the world (See Exhibit 13).

Exhibit 13. U.S. vs. Rest of World Refinery Yields (Percent Products)

Product	US	Rest of World
Gasolines	47.8%	20.4%
Distillate (incl. Jet)	29.5%	38.9%
Residual Fuel	3.7%	17.6%

Source: 2003 World Output of Refined Petroleum Products, EIA

Over the study period, Exhibit 14 shows that the average crude quality in the U.S. has declined from about 32 API gravity to about 30 API, indicating that U.S. refiners have been improving capability to process the heavier global crude oils that are less expensive to purchase. API gravity is a measure of crude oil density. The lower the value, the heavier or denser the crude oil is. The increase in API for California crudes reflects the transition to more imported crude as production level of low API California crudes have declined.

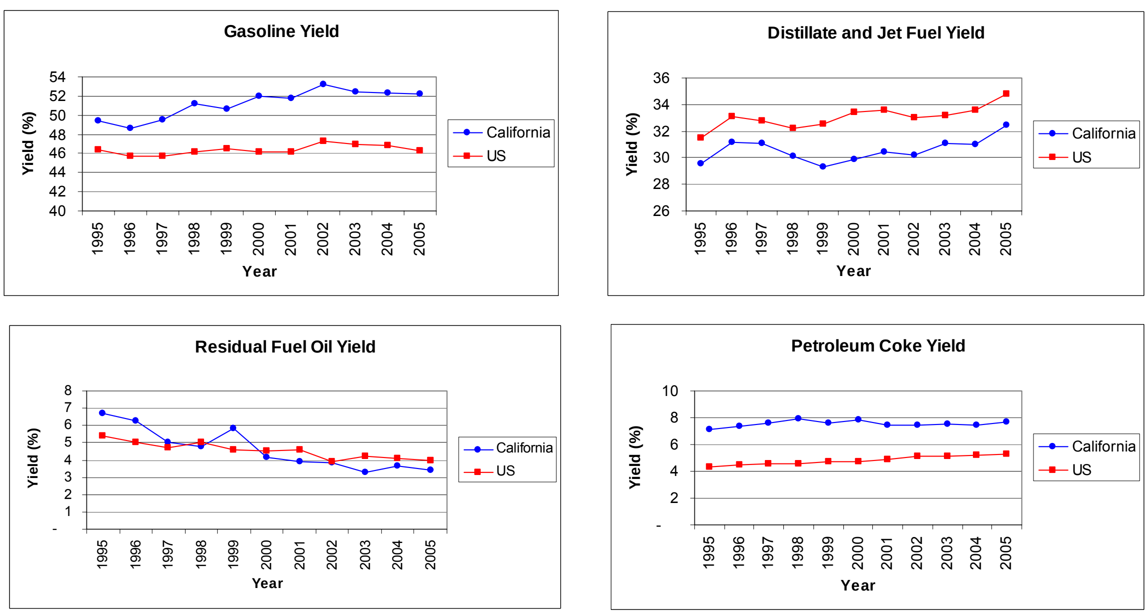
Exhibit 14. CA vs. U.S. API Gravity of Crude Processed

Year	California	US
1995	23.12	31.30
1996	23.32	31.14
1997	23.64	31.07
1998	23.93	30.98
1999	24.66	31.31
2000	24.65	30.99
2001	25.00	30.49
2002	25.29	30.42
2003	25.52	30.61
2004	25.55	30.18
2005	25.40	30.21

Source: Energy Commission Staff calculations from domestic and foreign crudes processed and EIA Petroleum Navigator.

A more specific comparison of California refinery yields versus the U.S. yield indicates that California refineries yield a higher percentage of gasoline than the U.S., and lower distillate yields. Yield of residual fuel is lower in California and petroleum coke yield is substantially higher (See Exhibit 15).

Exhibit 15. U.S. vs. California Refinery Yields, % Crude Input

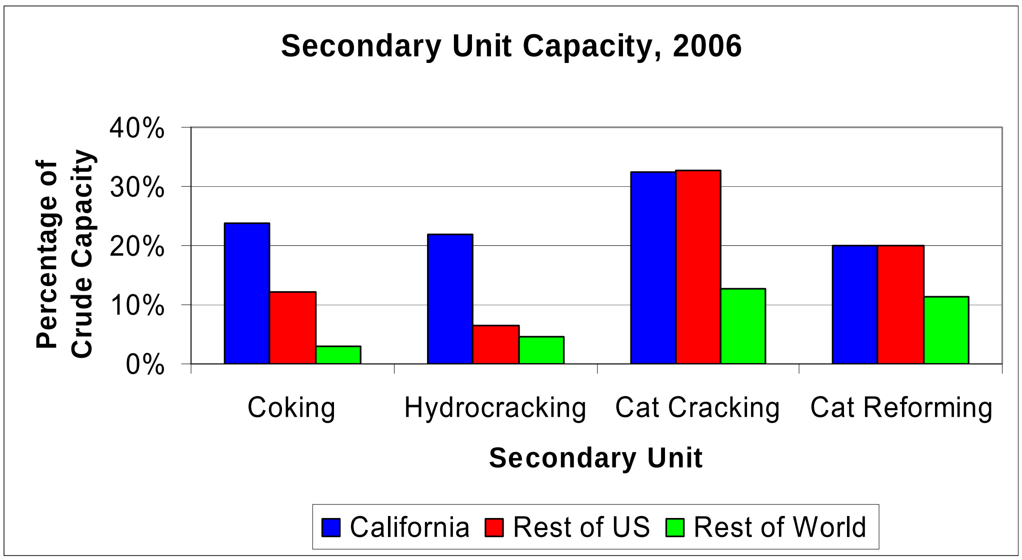


Source: EIA Petroleum Navigator Refinery Yield, CEC California Monthly Inputs and Outputs.

These data indicate that California refineries have higher overall clean product (gasoline plus distillate) yields than the U.S. average at 84.6 percent vs. the U.S. average at 81.1 percent. This is in large measure because California refineries have a higher complexity, and more severe upgrading than the average U.S. refinery. In addition, California's average crude gravity in 2005 was 25.4 API[11] vs. the U.S.

average of just over 30 API. California's much higher coking and hydrocracking capacity (see Exhibit 16) allow the conversion to a greater overall gasoline and distillate yield from a challenging crude input. The much greater coking capacity as a percent of crude explains California's lower residual fuel production, and much higher yield of petroleum coke than other regions.

Exhibit 16. Key Secondary Unit Capacities, % Crude Input



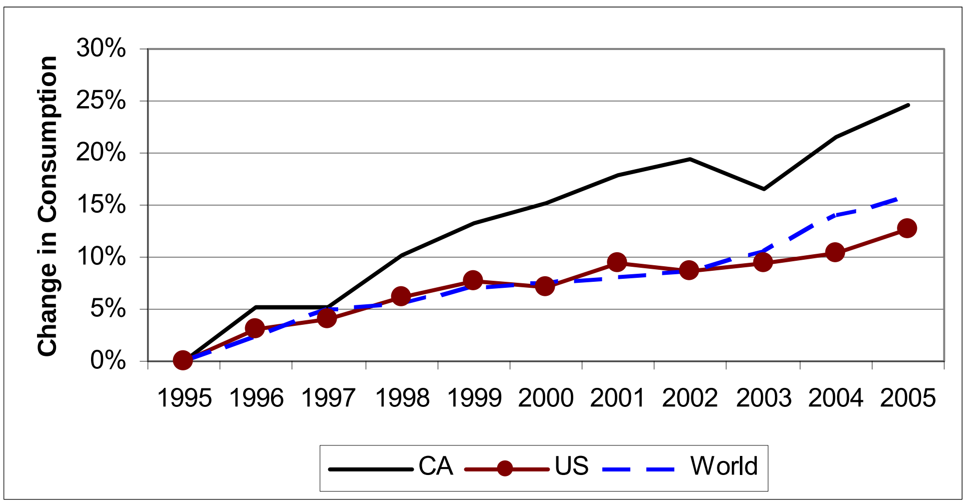
Source: Oil and Gas Journal, *Worldwide Refining Survey*

The capability of California's refining system to generate high clean product yields from much poorer quality crude is not without a price. The greater complexity of operation and the required design of the refinery hardware and metallurgy to handle the high pressure operations, heavy and high TAN[12] California crudes, and meet stringent product specifications mean that 1) the cost of refinery process units is very high compared to other refining centers and 2) refinery operational costs[13] can be higher than PADDs 1-4

1.1.2 Product Demands

The consumption of petroleum products has grown much faster in California as compared to the United States and the world as a whole during the last ten years. Consumption in California grew by 23 percent in the past ten years as compared to 12.6 percent growth in United States and a 15.6 percent increase in worldwide consumption during the same period. Exhibit 17 shows the aggregate change in consumption of key petroleum product categories since 1995 for California, United States, and the world.

Exhibit 17. Change in Consumption of Gasoline, Distillate (incl. Jet Fuel) and Residual Fuel Oil from 1995 to 2005



Source: EIA Prime Supplier, CA Taxable Motor Gasoline Sales and BP Statistical Review of World Energy, June 2006

The transportation sector has been the main area of increase in petroleum product consumption world-wide. Consumption of lighter fuels such as gasoline, which is used in personal transportation vehicles over relatively small distances, and distillates, which are used in commercial vehicles and for freight transportation, has increased at a faster rate than heavier fuel oils. There are several drivers for the increase in transportation sector fuel consumption. With the advent of globalization, the movement of goods and people across regions has grown rapidly. As the wealth of developing countries is increasing, purchase and use of motor vehicles in these countries is also increasing. In the developed countries such as the United States, heavier fuel oil in industrial and electric power generation has been substituted in large part by cleaner burning fuels such as natural gas, thus slowing the growth of heavier fuel oil consumption. There have been very few alternatives for gasoline and diesel in the transportation sector until recently. Use of compressed natural gas in fleet vehicles in some countries has remained a niche market. With high petroleum prices of the last few years, plant-based fuels such as ethanol and bio-diesel have come to the fore. However, their use is still a small percentage of the petroleum consumption and is likely to remain so for the foreseeable future.

Exhibit 18 shows the demand for the key product groups in 1995 and 2005 for California and compares it with the consumption in United States and the world.

Exhibit 18. Consumption of Key Petroleum Products in California, United States and the World, TBD

cc	Period	CA	US	World
Gasoline	1995	875	7,789	21,236
	2005	1,040	9,125	25,319
	Annual Average Growth Rate	1.8%	1.6%	1.8%
Distillate	1995	432	4,466	23,682
	2005	531	5,210	29,584
	Annual Average Growth Rate	2.9%	1.6%	2.3%
Residual Fuel Oil	1995	48	628	11,248
	2005	83	596	10,150
	Annual Average Growth Rate	7.2%	0.0%	-1.0%

Note: Distillate includes kerosene type jet-fuel
Sources: CA Gasoline from California Board of Equalization, World numbers from BP Statistical Review, 2006, Other numbers from EIA Prime Supplier Volumes

In the last ten years, the annual average growth in gasoline consumption in California has grown faster than the United States and the world as a whole. Distillate consumption in California has grown nearly twice as fast as the United States as a whole and at a faster pace than the world. Residual fuel consumption has actually registered a stronger growth in California than gasoline or distillate although the volume is much small in comparison. This strong growth is an exception to the overall trend of higher growth rate in lighter fuels since residual fuel is used only for vessel bunkering in California and the California ports serve as a gateway to the entire country for goods manufactured in China and other countries of the Far East. Residual fuel oil consumption in United States was the same in 2005 as in 1995 and declined by an average of 1 percent per year in the world.

Product Demand Trends in California

In 2005, California consumed 1,689 thousand barrels per day of petroleum products including gasoline, diesel, jet fuel and residual fuel oil. Of this, gasoline constituted 62 percent of the consumption, diesel and jet fuel 17 percent each, and residual fuel the remaining 5 percent. As Exhibit 19 shows, consumption of petroleum products in California has grown nearly 20 percent between 1995 and 2005.

Exhibit 19. Consumption of Key Petroleum Products in California from 1995 to 2005, TBD

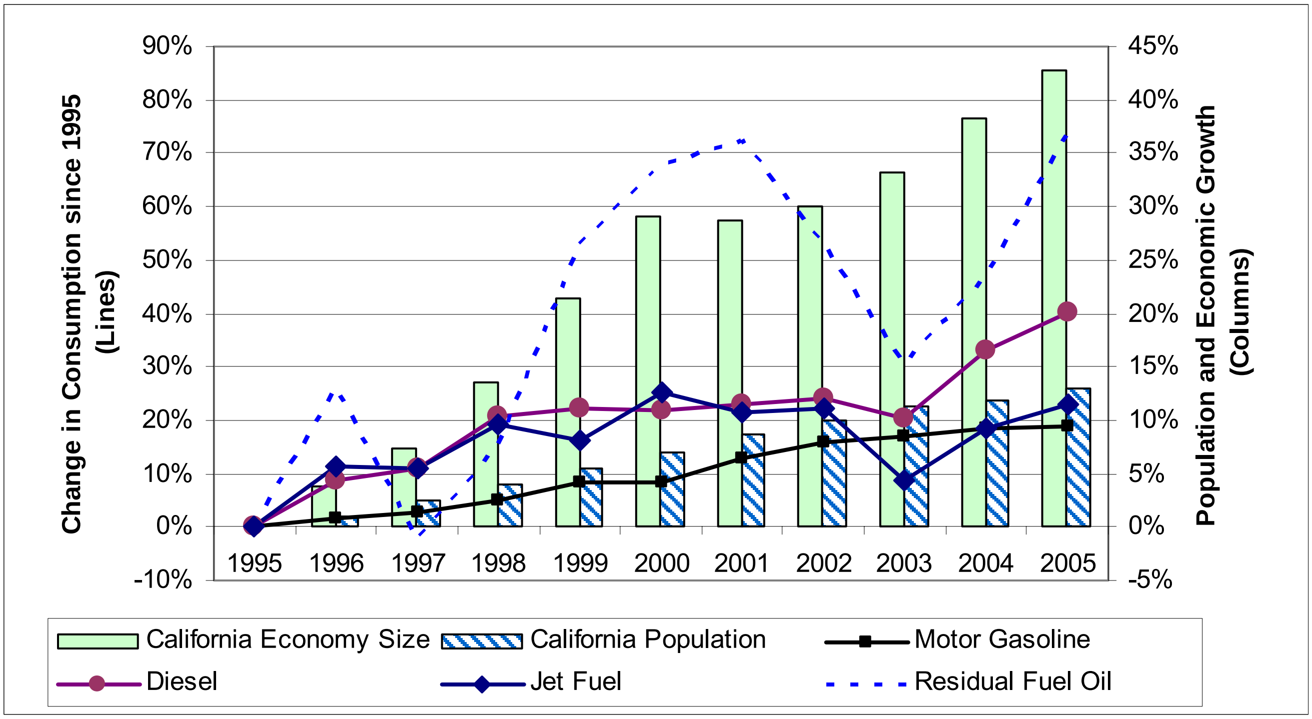
Year	Motor Gasoline	Diesel	Jet Fuel	Residual Fuel Oil
1995	875	202	230	48
1996	889	219	257	60
1997	900	224	255	46
1998	918	243	275	55
1999	946	247	268	73
2000	946	245	288	80
2001	986	248	280	82
2002	1,012	250	282	73
2003	1,022	243	250	62
2004	1,035	268	273	70
2005	1,040	283	283	83

Source: Gasoline: CEC, Board of Equalization, taxable sales data, Other products, and EIA prime suppliers data.

Gasoline consumption has averaged an annual growth rate of 1.8 percent over the last ten years. The growth in gasoline demand has followed the trend in population increase, which grew by an average of 1.3 percent in the same period. Demand for diesel (on-road and off-road combined) grew at 3.5 percent, a much faster pace than that of gasoline.

The consumption of diesel is driven by economic activity. California's economy grew at an average 4.3 percent over the last ten years. Between 2000 and 2003 the slowdown in California's economy from a slump in the technology sector was reflected in the demand for diesel as well. Diesel consumption was 1 percent lower in 2003 than in 2000. However, over the last two years, diesel consumption has grown rapidly, higher fuel prices notwithstanding, as the economy has posted strong gains. Exhibit 20 shows the changes in petroleum product consumption in California versus its population and economic growth[14] since 1995.

Exhibit 20. Growth in Petroleum Product Consumption vs. Growth in Population and Economy Size for California, 1995-2005



Source: Energy Commission Taxable Fuels database, EIA Prime Suppliers, US Census Bureau, US Bureau of Economic Analysis-http://www.bea.gov/bea/regional/gsp.htm

Consumption of jet fuel has increased at an average rate of 2.3 percent since 1995. However, jet fuel was affected by both the slump in the technology sector as well as the post 9/11 effect on travel. Jet fuel consumption declined by 13 percent between 2000 and 2003, but has since recovered.

Residual fuel oil consumption is the smallest in absolute volume terms but has shown the strongest relative growth among all petroleum products. Its consumption has increased at an annual average of 7.2 percent over the last ten years. In the United States as a whole, 40 percent of the residual fuel is consumed for electric power generation, another 40 percent for vessel bunkering, and the remaining 20 percent in the industrial and commercial sectors. However, in California, over 99 percent of the residual fuel is consumed for vessel bunkering. Stricter air emissions standards have kept the consumption of residual fuel in the electric, commercial, and industrial sectors at negligible levels for the last ten years. Fuel consumption for vessel bunkering dropped sharply between 2001 and 2003 as a result of the economic slowdown but regained those losses by year 2005 as marine movements of cargo container vessels into California increased with a stronger economy.

Petroleum Product Demand in Neighboring States

The western part of the United States is relatively isolated from the Midwest and eastern portion of the country with regards to the petroleum infrastructure. The Rocky Mountains present a significant obstacle in building oil and gas pipelines from the energy supply centers of the U.S. Gulf Coast and the Midwest. Therefore, the states on the West Coast - California, Oregon, and Washington – along with the neighboring states of Arizona and Nevada, have their own energy interaction largely independent from the eastern part of the country. The western states (all belong to PADD 5) satisfy most of their demand from local production or marine imports rather than pipeline movements from outside the region.

California exports petroleum products to its three neighboring states: Arizona, Nevada, and Oregon. Product movements from California to Oregon are less than 50 TBD and take place by tanker regularly and by truck occasionally in small quantities. But Arizona and Nevada are significantly dependent on California's petroleum infrastructure for their product supply. In fact, nearly all of Nevada's fuel consumption and about 60 percent of Arizona's fuel consumption is satisfied by petroleum products shipped from or through California. Changes in product demand as well as supply options for petroleum products in these two states directly impacts California.

Arizona

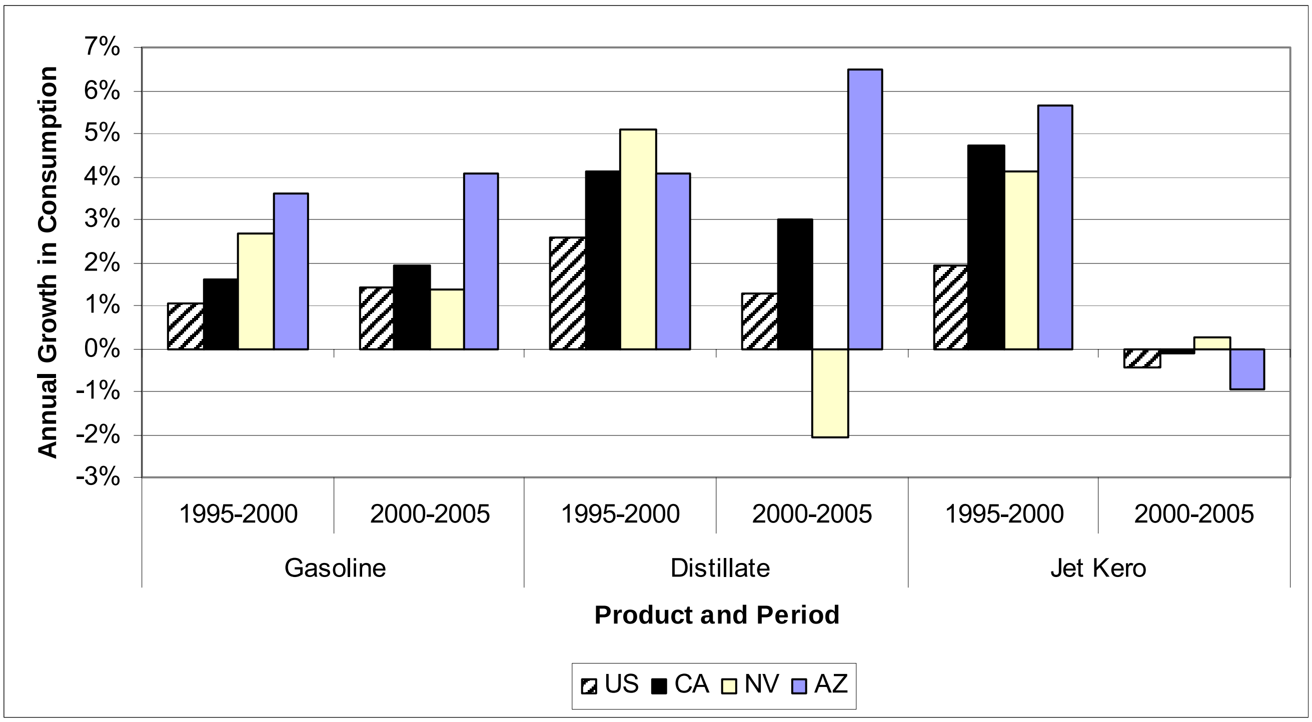
The total demand for petroleum products in Arizona was 243 TBD in 2005. Arizona product demand was entirely in the transportation sector and comprised of 67 percent gasoline, 24 percent diesel and the remaining 9 percent jet fuel in 2005. Gasoline demand grew by 10 percent and 12 percent in 2004 and 2005 respectively, whereas diesel demand grew by 10 percent and 14 percent during the same periods. The steep increases in product demand are driven by the strong growth in population and freight traffic.

Nevada

Nevada petroleum product demand is smaller than Arizona and California but has been growing very rapidly for the last few years. Clark County in Las Vegas, Nevada is one of the fastest growing metropolitan areas in the country. Similar to California and Arizona, all the petroleum demand consists of gasoline, diesel, and jet fuel for transportation use. In 2005, Nevada consumed 102 TBD of petroleum products, of which gasoline accounted for 60 percent, diesel 20 percent, and jet fuel the remaining 20 percent.

Exhibit 21 shows that gasoline demand in California, Arizona, and Nevada grew at a faster pace than the United States as a whole over the past ten years. Arizona had the fastest growth in gasoline demand, growing twice as fast as demand in California. Nevada's gasoline demand grew faster than California before 2000, but has slowed after 2000 to a lower growth rate.

Exhibit 21. Comparison of Product Consumption Growth for Key Petroleum Products between California, Arizona, Nevada and the United States from 1995 to 2005



Sources: CA – CA BOE Taxable Fuel Sales Database, Bonded Fuels – EIA Form-814 Company-level Imports, Rest - EIA Petroleum Navigator Prime Supplier Volumes

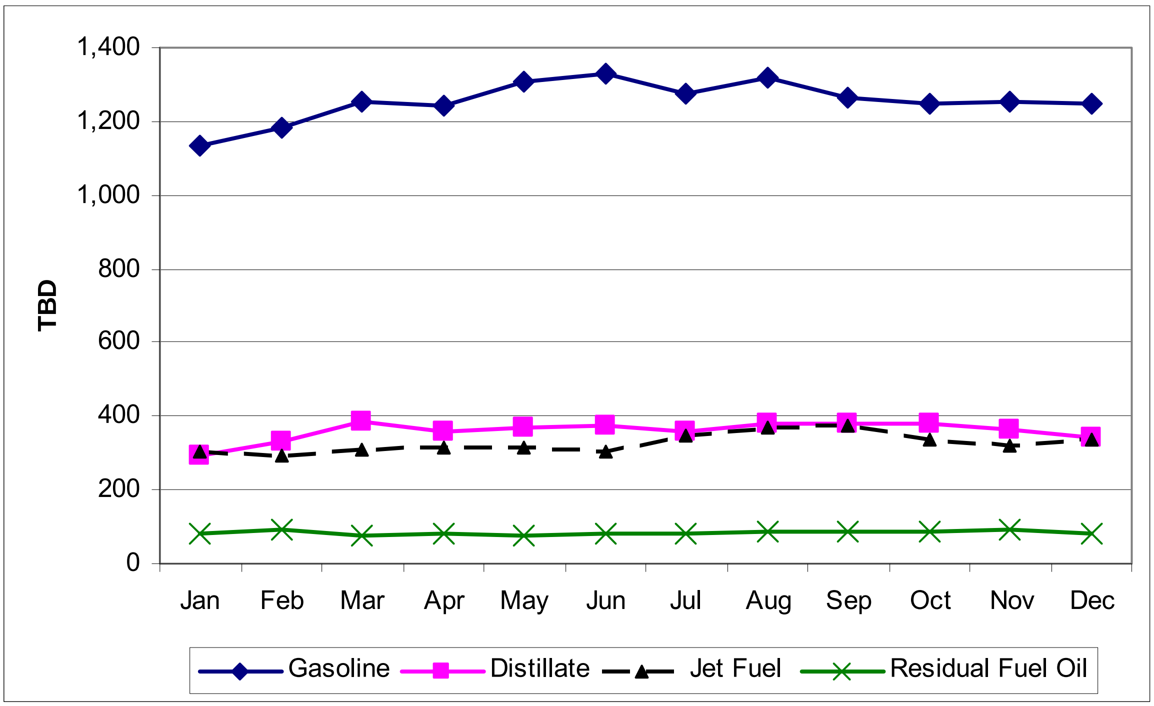
Distillate demand in California and Arizona registered a much stronger average growth over the past ten years as compared to the national average because of higher freight movement from the west coast to the mid-west and the east coast. Jet fuel demand in all three states grew at a faster pace than the national average from 1995 to 2000. After experiencing declines in the 2002-2004 period, jet fuel demand increased significantly in 2005.

Seasonality of Petroleum Product Demand

Petroleum demand in California, Arizona, and Nevada shows seasonal variation depending on the type of fuel as shown in Exhibit 22. In general, petroleum demand is higher in the summer months as compared to the winter months as seen in. Gasoline demand between May and September was on average 6.2 percent (75 TBD) higher than in the other months of 2005. During June 2005, gasoline demand peaked at 1,331 TBD, which was 17 percent higher than in January 2005 when demand was at its lowest.

Distillate consumption has a longer ‘high season’ than gasoline and is higher annual average from March through October. During the months of December, January, and February, distillate demand drops substantially. The demand during the high season is 15.6 percent higher on average than during the winter months. For example, distillate demand peaked at 383 TBD during October 2005, which was 30 percent higher than demand in February 2005.

Exhibit 22. Seasonality of Petroleum Product Consumption in California, Arizona, and Nevada; Monthly Consumption in 2005



Source: EIA Petroleum Navigator Prime Supplier Volumes

Jet fuel consumption averages 314 TBD for most of the year except the peak months of July through September, when the demand averages 363 TBD (16 percent higher). The demand in the peak month of September was 28 percent higher than in February 2005, when demand was its lowest. Residual fuel demand held nearly steady throughout the year and its small volumes lead us to exclude it from the rest of the seasonality discussion.

The seasonal variation in the demand for the three products (gasoline, distillate, and jet fuel) results in combined petroleum product demand averaging 7 percent higher for May through September as compared to other months. At its peak in August, the product demand for these three products is 336 TBD, or 19 percent higher than it's lowest point in January.

The lowest demand months of January and February coincide with the typical periods of refinery maintenance work. However, the 19 percent increase in demand during the peak periods means that a refinery disruption, or cargo delay, can create more problems than in the winter. If days supply inventory runs around 13 days state-wide (total inventory), then unless inventory runs higher in the summer, there are about two days less of supply held in inventory during the summer months. Since the real "working inventory" is less than the total inventory of 13 million barrels, any refinery outages occurring from the heat or power problems will be more difficult to recover from.

1.1.3 Imports and Exports Trends

Import and export of petroleum products to and from California needs to be considered by looking at a combined system of California, Arizona and Nevada. As noted earlier, California is the source of a significant portion of supply for Arizona and Nevada, hence demand growth in those states is critical to California supply issues.

Arizona

Arizona has no refinery, and all the product consumed in the state is imported from neighboring states. Two main Kinder Morgan Pipelines, the "East Line" coming from El Paso, Texas, and the "West Line", coming from California via Yuma, Arizona supply nearly all of Arizona's product. A very small portion of the fuel is trucked in from bordering states. In 2005, California supplied about 60% of the petroleum products consumed in Arizona through the West Line.

The East Line runs from El Paso, Texas to Tucson, Arizona and then to Phoenix, Arizona. Till recently this pipeline had a capacity of 87 TBD from El Paso to Tucson and 49 TBD from Tucson to Phoenix. In June 2006, Kinder Morgan expanded the East Line to 147 TBD from El Paso to Tucson and 99 TBD from Tucson to Phoenix. Most of the existing 87 TBD capacity had been utilized in the last 10 years and any incremental growth in Arizona's product demand was supplied from California. Thus, California's product exports to Arizona have increased steadily from about 108 TBD in 1995 to 154 TBD in 2005.

The product transported through the East Line is primarily supplied by three refineries situated in El Paso (TX), Navajo (NM) and McKee (TX) who are linked by other pipelines to El Paso. Another product pipeline, Longhorn, connects Galena, TX in the Houston area with El Paso. Product shipments on the Longhorn pipeline have been sporadic in the past and there are possible talks of converting this pipeline to a crude pipeline to improve its utilization. However, with expansion of the East Line, there is now operational feasibility in addition to economic incentive for the Gulf Coast refineries to ship products via the Longhorn and the Kinder Morgan pipelines to the Western States. The pipeline shipping cost to Phoenix is more attractive than the cost of marine shipment via the Panama Canal to California.

Nevada:

Most of Nevada's petroleum product is supplied by the Calnev pipeline from southern California to Las Vegas and Kinder Morgan's pipeline from northern California to Reno. Exports of products from California to Nevada has increased by 24% from 133 TBD in 1996 to 164 TBD in 2005 as Nevada's demand has registered an annual average growth of 3.1%.

Overall Supply and Demand

Since 1995, the increasing demand for products in California, Arizona and Nevada combined with the slower increases in refinery capacity and constraint on the Kinder Morgan East line has resulted in an increase of marine imports into California from both foreign and domestic sources. The sources of additional supply into the three-state region include the following:

Foreign Imports: these are products imported from foreign countries. Exhibits will be presented showing 1) actual history of the finished product imports (and exports) and 2) actual history of both finished and unfinished imports. The unfinished imports included products such as MTBE, gasoline blending components, ethanol, and unfinished gas oils for refinery processing.

Domestic Imports: these are products moving into the three state region from U.S. sources. This includes 1) Marine products from PADD 3 (U.S. Gulf Coast), 2) Marine products from PADD V (Washington refiners), 3) Pipeline products from PADD 3, 4) Ethanol railcars from PADD 3 (primarily). Domestic exports out of this region are primarily gasoline into Oregon from the Bay area, with smaller volumes of distillate and jet.

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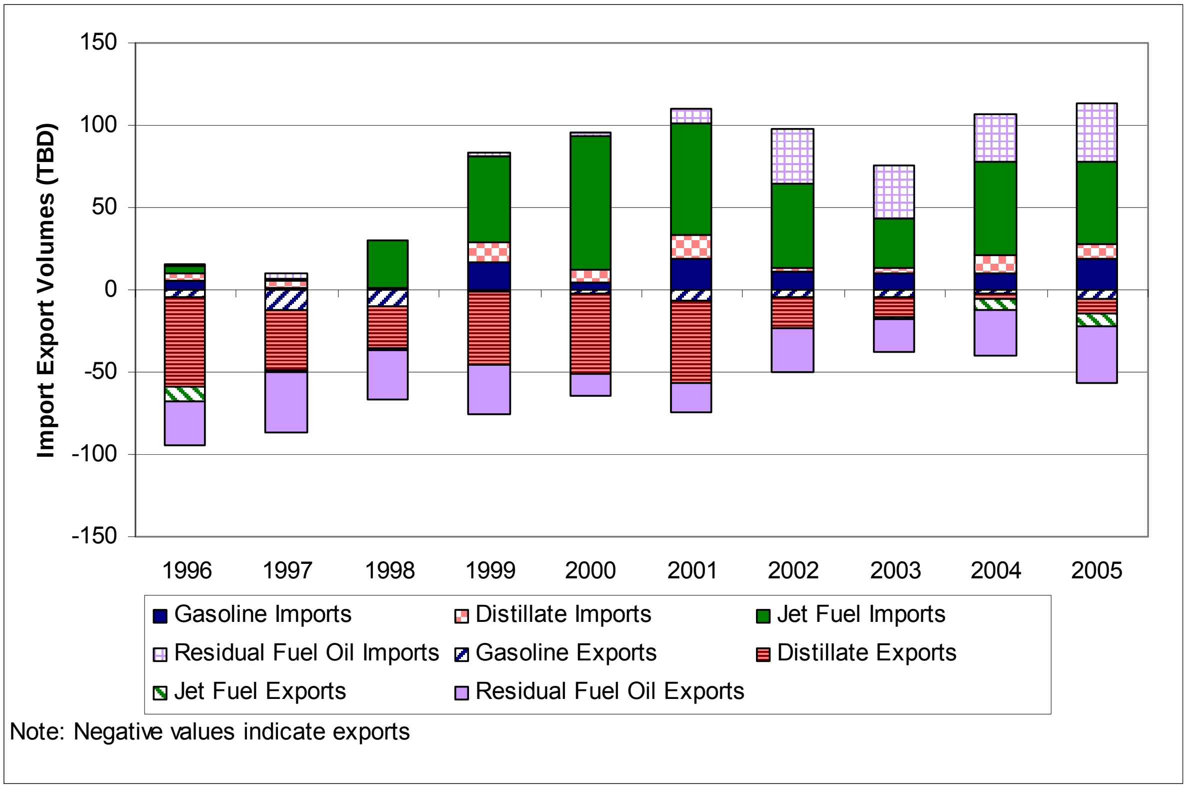
Foreign Imports and Exports: Finished Products

California has changed from a net foreign exporter in 1997 to a net foreign importer of petroleum products. California exported 98 TBD and imported 12 TBD of products in 1995 from foreign countries. In 2005, it exported 56 TBD and imported 113 TBD of products from foreign countries as seen in Exhibit 23. Jet fuel formed the largest share of finished petroleum products imported in 2005, 70% of which was bonded fuel marked for use on international flights leaving the United States.

The bulk of product exports from California has been distillate fuel and residual fuel. Distillate export volumes declined substantially over the study period due to increased demand growth in California.

Exhibit 23 Foreign Imports and Exports of Finished Products in California, 1996-2005



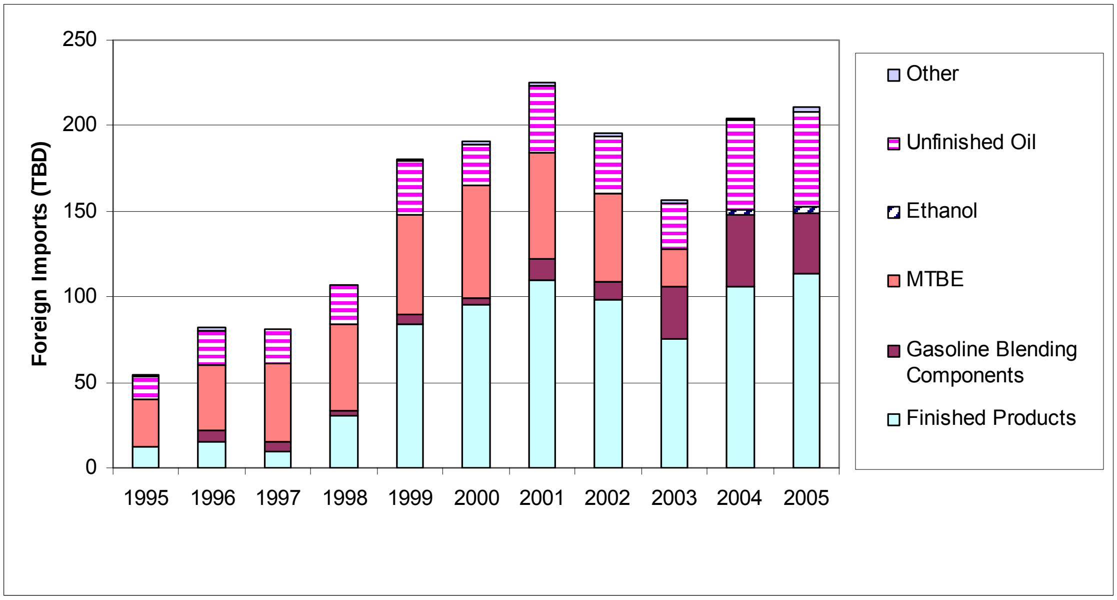
Source: EIA Form-814 Company-level Imports and export data received from EIA

Foreign Imports of Unfinished Products

In addition to the finished product imports, another 98 TBD of unfinished products were imported in 2005 as seen in Exhibit 24. The unfinished products include gasoline blending components, unfinished gas oils and other petroleum products that were used by California refineries. Until 2002, MTBE formed a significant portion of the unfinished product imports. In 2003, MTBE imports declined significantly and then stopped in 2004 as ethanol was used as an oxygenate in California gasoline instead. California produced about 0.5 TBD of ethanol in 2005, foreign imports accounted for 4 TBD and the rest was sourced from the Midwest.

Noteworthy in this historical view is that the volume of gasoline from foreign sources (primarily blendstocks) has increased in the past couple years to partially offset the loss of MTBE. In addition, unfinished oils have increased in 2004 and 2005. These oils are processed in the refineries to increase gasoline and distillate yield, and have worked to bolster refinery supply. Exports of unfinished products from California are negligible.

Exhibit 24 Foreign Imports of Unfinished Petroleum Products (above Finished Products) into California, 1995-2005



Source: EIA Form-814 Company-level Imports

Total Imports & Exports

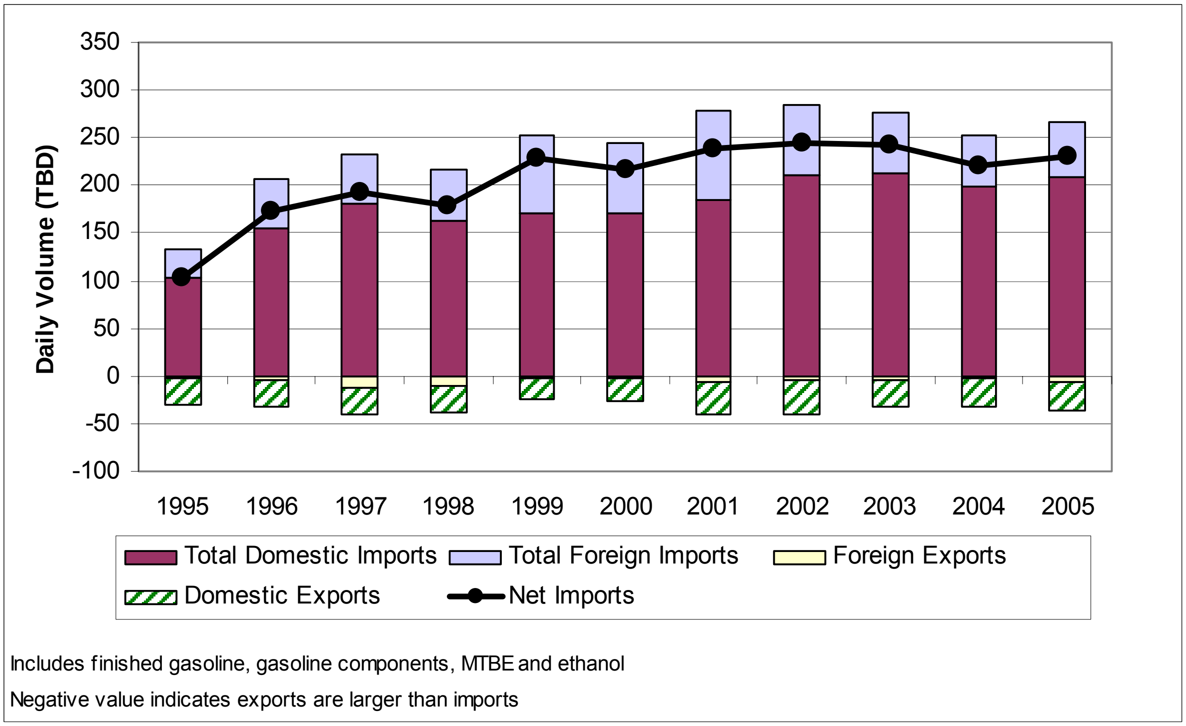
The domestic movement of products into the region is primarily gasoline or gasoline components over the last few years although there has been some movement of distillates on the Kinder Morgan East line into Arizona and marine movements from Washington state.

Gasoline. Exhibit 25 shows the volume of gasoline that is imported into and exported from the three state region. The import volumes into the Kinder Morgan East line and via Jones Act vessels are based on actual movements. Ethanol is estimated based on usage percentages in CARBOB gasoline since 2003. Volumes from Washington refiners are estimated to balance.

The volumes of domestic imports can be finished gasoline supply from PADD 3 via Kinder Morgan, blendstock from Jones Act vessels, Ethanol from the Midwest, and finished gasoline and gasoline blendstocks from the Northwest.

Gasoline imports are somewhat offset by marine supply of finished gasoline exports into Oregon. These exports (about 30 TBD) will be reflected in the net import dependency determination.

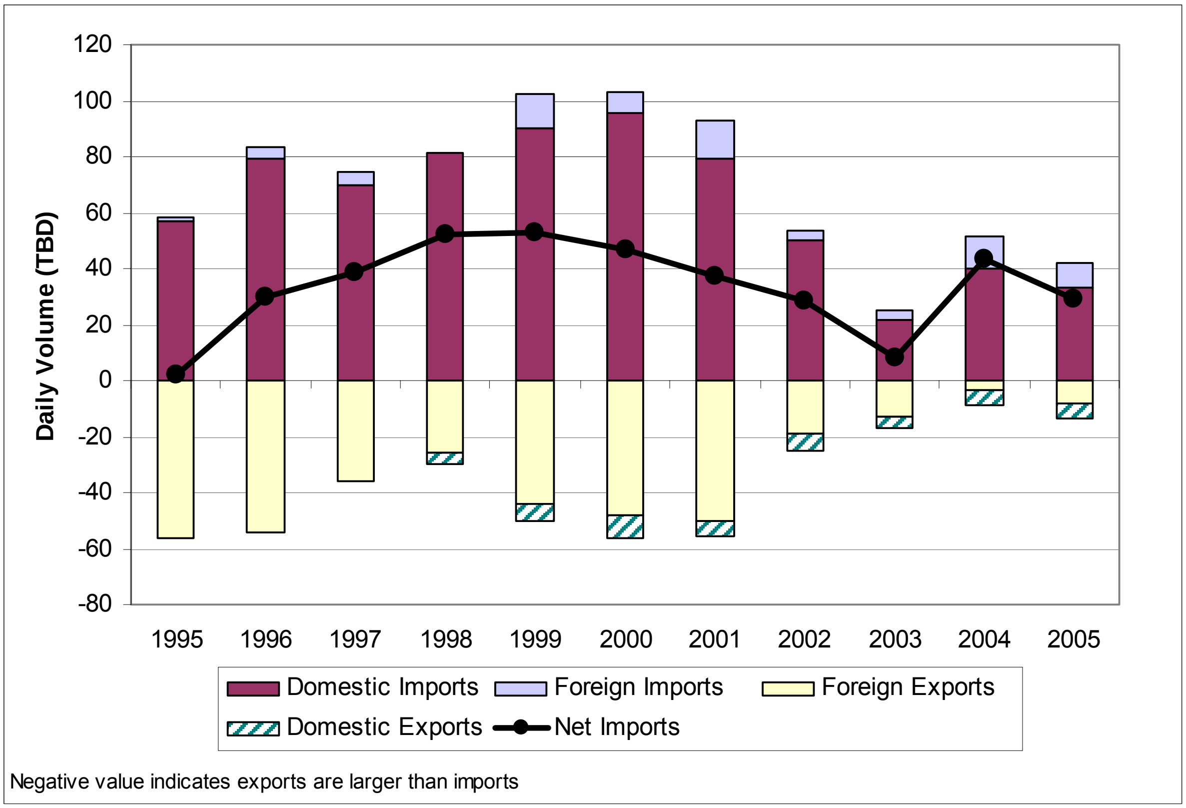
Exhibit 25. Total Imports and Export of Gasoline in CA,AZ and NV, 1995-2005



Source: EIA Form-814 Company-level Imports, Wilson Gillette & Co Jones Act Data, Kinder Morgan Pipeline Flows and foreign export data provided by EIA.

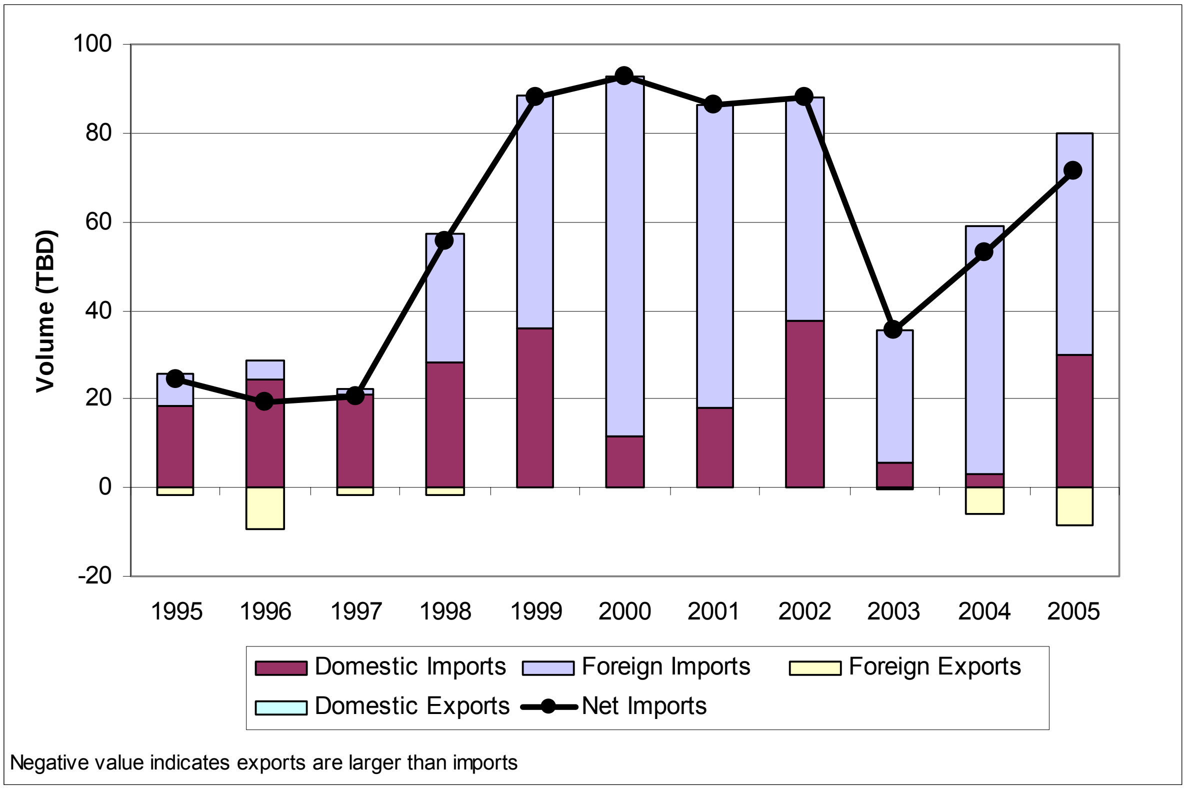
Distillate and Jet Fuel: Exhibit 26 shows the year by year domestic import and export history for distillate, and Exhibit 27 shows the same data for jet fuel. Domestic imports of distillate were high early in the period to support foreign exports of higher sulfur distillate. As California distillate demand grew and refinery hydrotreating capacity increased, both import and export volumes declined. For jet fuel, imports have been high, although demand reductions during the recession following the events of September 11, 2001 resulted in lower imports in 2002 and 2003.

Exhibit 26. Total Imports and Exports of Distillate in CA, AZ and NV, 1995-2005



Source: ICFI Analysis based on data from various sources

Exhibit 27. Total Imports and Exports of Jet Fuel in CA, AZ and NV, 1995-2005



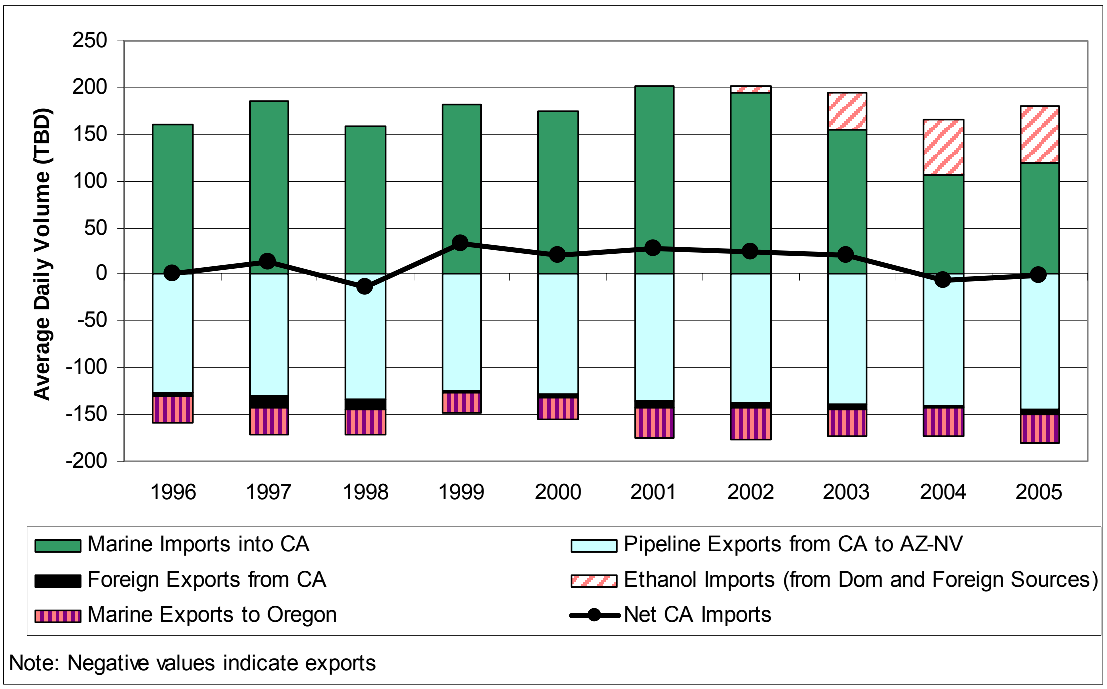
Source: ICFI Analysis based on data from various sources

Imports and Exports around only California

The section below examines the net input and output of products from all sources, domestic and foreign, outside California.

Exhibit 28 shows the high volume of gasoline entering and leaving California. Marine imports and ethanol by railcar are the primary imports while product moving to Arizona, Nevada and Oregon are exported. The trend shows increasing exports over the past ten years. Import volumes were reduced as MTBE imports were eliminated in 2003 and refinery gasoline production increased somewhat. The high volume of exports adds to the volume of product that California's distribution system must handle in addition to that required to satisfy the local consumption.

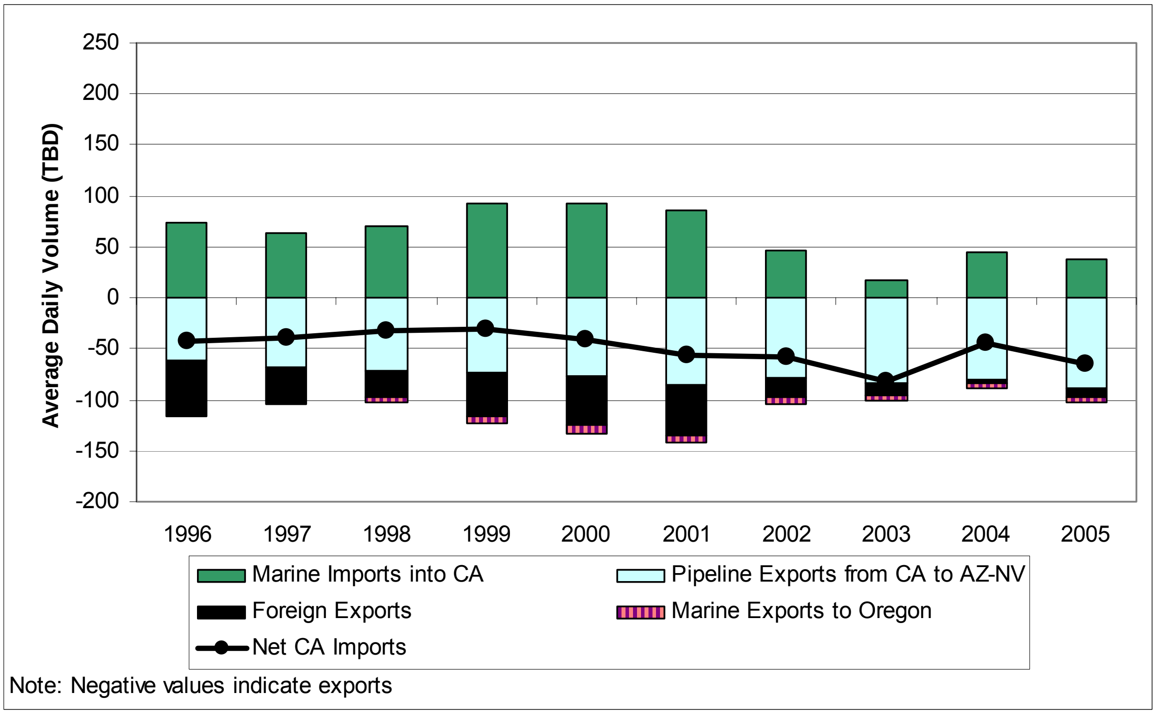
Exhibit 28. Gasoline Movements in California



Note: Gasoline includes blending components
Source: EIA Form-814 Company-level Imports, Wilson Gillette & Co Jones Act Data and Kinder Morgan Pipeline Flows

In 2005, California imported 37 TBD of finished distillate products. Foreign imports accounted for only 9 TBD and the rest came from Washington state refineries. Foreign imports of distillate have ranged from 2 TBD to 15 TBD in the past tem years but do not exhibit a trend in any one direction. However, imports from the Washington state refineries that act as a supply source needed to balance California's import requirement, have been declining. From 1995 to 2002, distillate imports from Washington averaged 69 TBD, but over the past four years the average has dropped to 29 TBD. This decline in imports comes at the same time that exports of distillate to foreign countries from California has declined as seen in Exhibit 29.

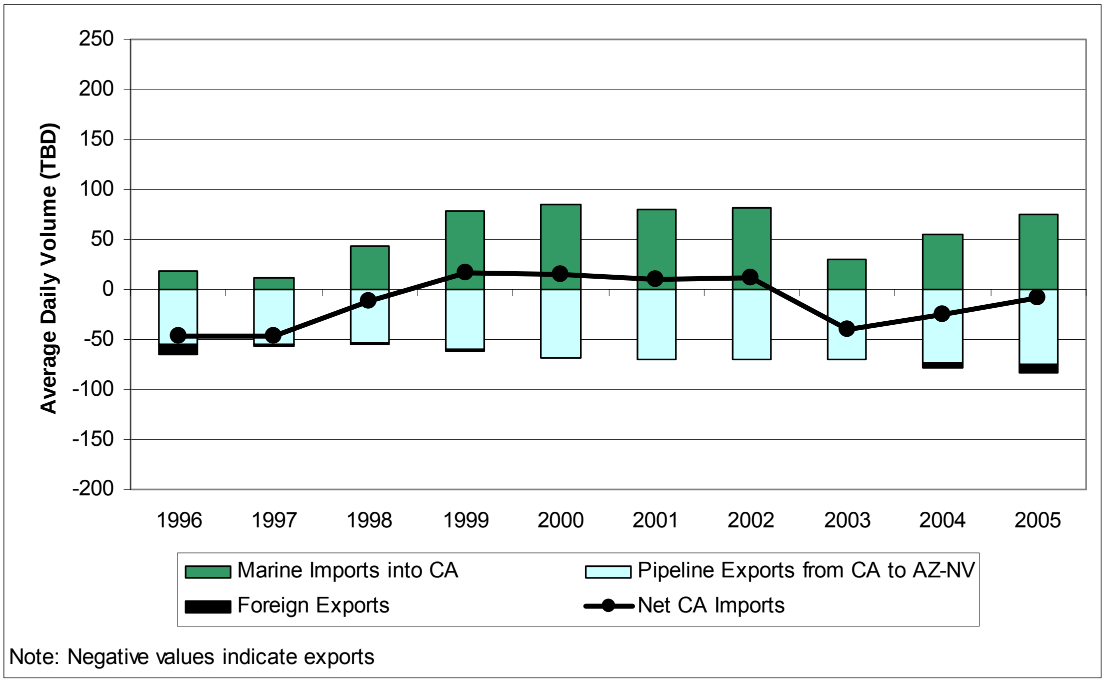
Exhibit 29. Distillate Movements in California



Source: EIA Form-814 Company-level Imports, Wilson Gillette & Co Jones Act Data and Kinder Morgan Pipeline Flows

Jet Fuel imports into California averaged 75 TBD in 2005 that included 50 TBD from foreign sources and the remaining from the Washington state refineries. Nearly 70% of the foreign imports of jet fuel are bonded to be used on international flights leaving California, Arizona or Nevada. Jet fuel import was at its peak of 92 TBD during 2000 but declined sharply by 2003 following the trend in demand among states of California, Arizona and Nevada. Pipeline exports of jet fuel from California to Arizona and Nevada have increased from 55 TBD in 1996 to 75 TBD in 2005. California also exports a small volume of jet fuel to foreign countries, primarily Canada. The overall imports and exports of jet fuel for California are shown in Exhibit 30

Exhibit 30. Jet Fuel Movements in California



Source: EIA Form-814 Company-level Imports, Wilson Gillette & Co Jones Act Data and Kinder Morgan Pipeline Flows

Residual fuel oil was imported at an average of 36 TBD during 2005. These imports were negligible until year 2000, but increased to about 33 TBD by 2002 and have stayed around that level since then. The increase in residual fuel oil imports has coincided with an increase in coking capacity of about 30 TBD between 1999 and 2002 in California refineries that took away some of the local residual fuel oil stream for production of higher value products.

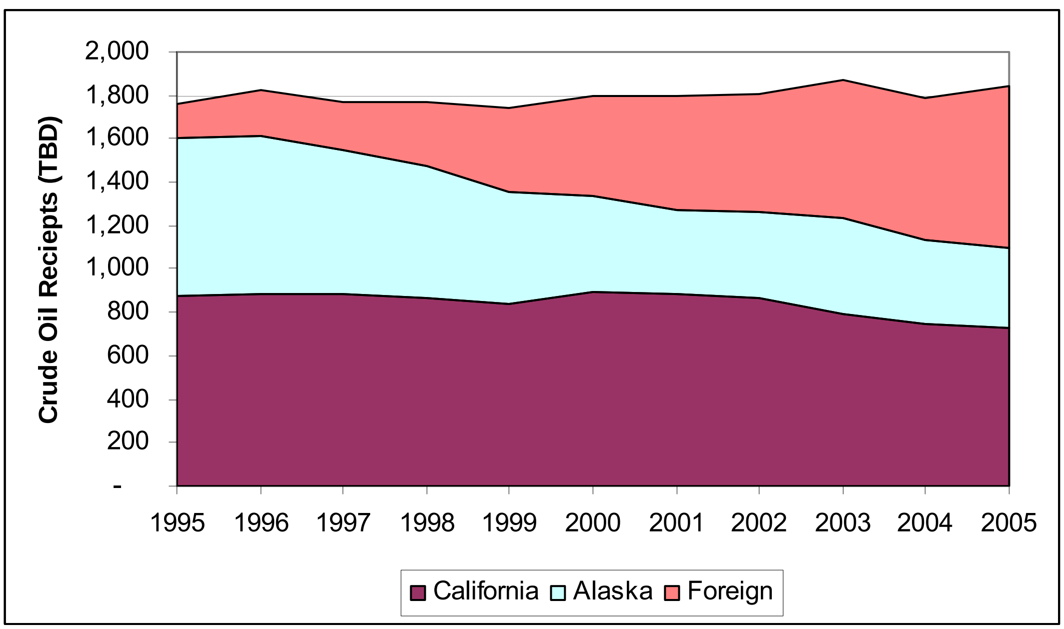
1.1.4 Dependence on Imports

California, Arizona and Nevada are dependent on both domestic as well as foreign sources to satisfy some of their product consumption needs.

Crude Oil Import Dependence

California's refineries consume crude oil produced within the state, some imported from Alaska (ANS, Alaskan North Slope) and the rest imported from foreign countries. Production of crude oil in California has declined 17% compared to it's level in 1995 and at the same time the amount of crude oil used in California's refineries has increased by 5%. The decline in local production has resulted in California's crude oil import dependence increasing from 50% in 1995 to 61% in 2005. In 1995, crude oil imported from Alaska satisfied 41% of California's demand, but the decline in ANS production has resulted in the ANS import volumes declining substantially to 20% in 2005 as seen in Exhibit 31

Exhibit 31. Sources of Crude Oil for California Refineries



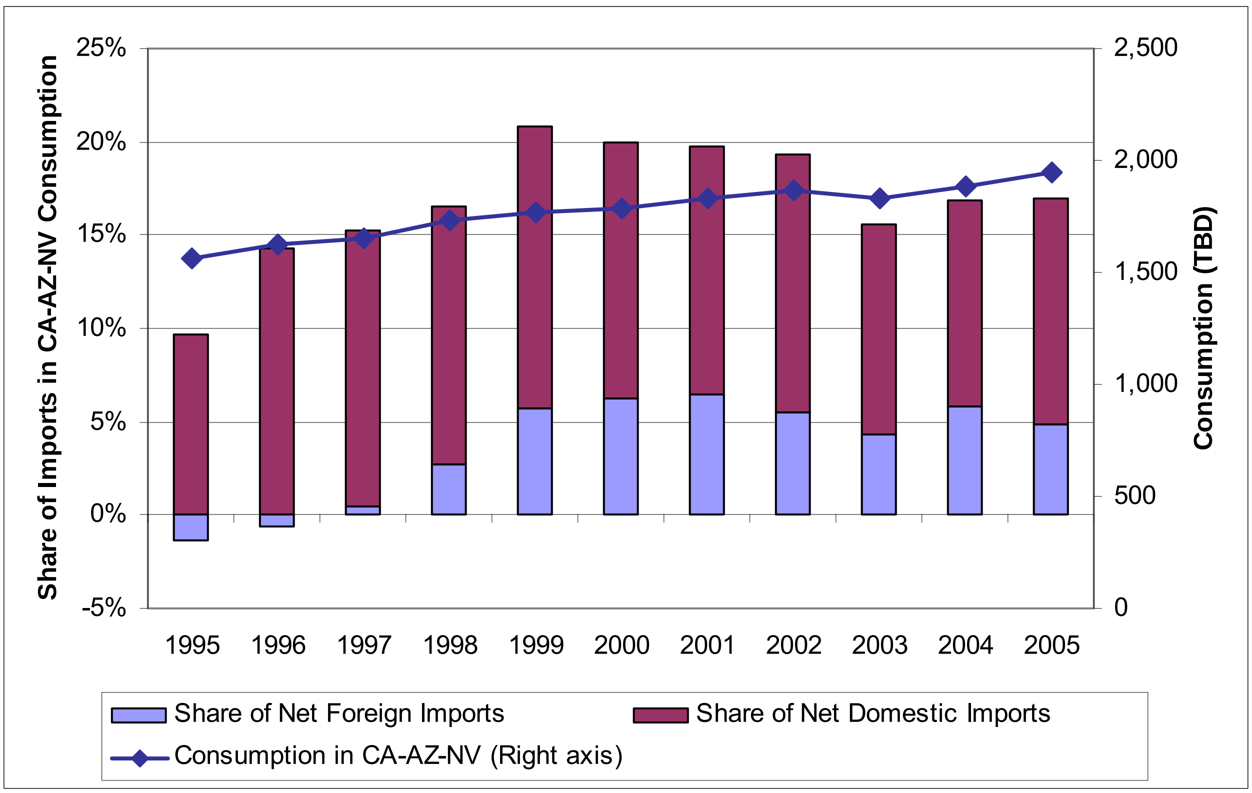
Source: CEC Oil Supply Sources into California Refineries, http://www.energy.ca.gov/oil/statistics/crude_oil_receipts.html.

The increasing gap between demand and domestic production has been filled with imports from foreign countries. Saudi Arabia is the single largest foreign supplier of crude oil to California accounting for 35% of the foreign imports in 2005. Ecuador, Iraq and Mexico were the other big suppliers of crude oil to California in 2005. In 2005, these four countries satisfied 79% of the foreign crude oil needs for California.

Net Product Import Dependency

Product dependency has been evaluated for California, Arizona and Nevada combined as these three states are primarily dependent on California's refineries and marine import infrastructure for their product supply. Some products are also exported from California to Oregon and foreign destinations. The total product imports less product exports is considered for the net product import dependency of these three states. The net product import dependency for gasoline, distillate and jet fuel combined is shown in Exhibit 32.

Exhibit 32. Net Product Import Dependency for CA, AZ, NV for Gasoline, Distillate and Jet Fuel, 1995-2005



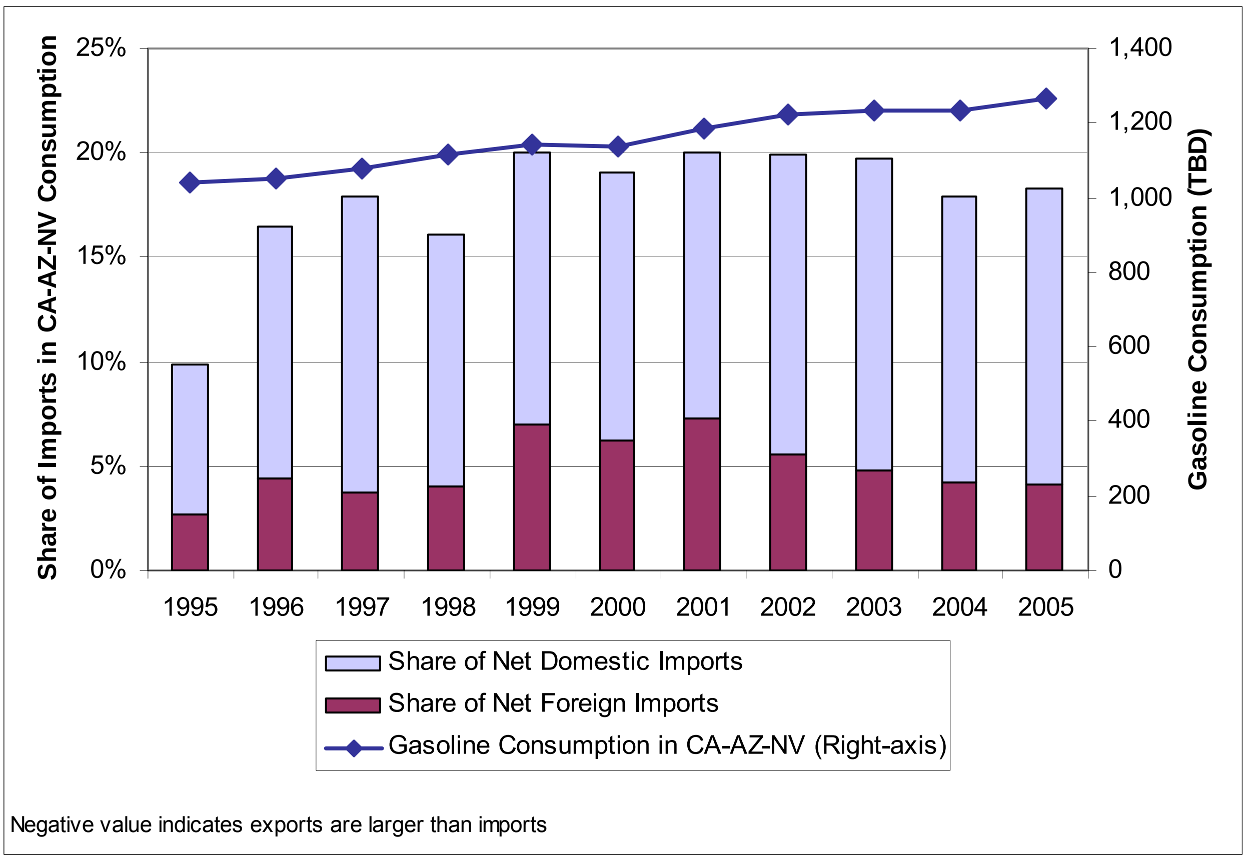
Source: ICF analysis of data received from various sources.

While California's crude oil import dependency has been steadily increasing due to a natural decline in local production, it's net product import dependency in 2005 was the same as in 1998. Between 1995 and 1998 California's product import dependency doubled from 8.3% to 16.6% as strong growth in demand outstripped increase refinery capacity. California's net product import dependency was it's peak during 1999, 2000 and 2001 but has declined since then due to a combination of increase in refinery production, decline in exports and slower growth in consumption after 2001.

Gasoline

As noted earlier, gasoline imports into the three state region come from multiple sources. The overall dependence is based on the sum of the gasoline imports (foreign, domestic, ethanol, MTBE, etc.) less exports. The total net gasoline imports in 2005 were 231 TBD, including ethanol from the Midwest and foreign and domestic imports. The overall net import dependency for gasoline and gasoline components in the 3 state region was just over 18 percent in 2005 (See Exhibit 33).

Exhibit 33. Gasoline Import Dependency for CA, AZ, NV



Source: ICF analysis of data received from various sources.

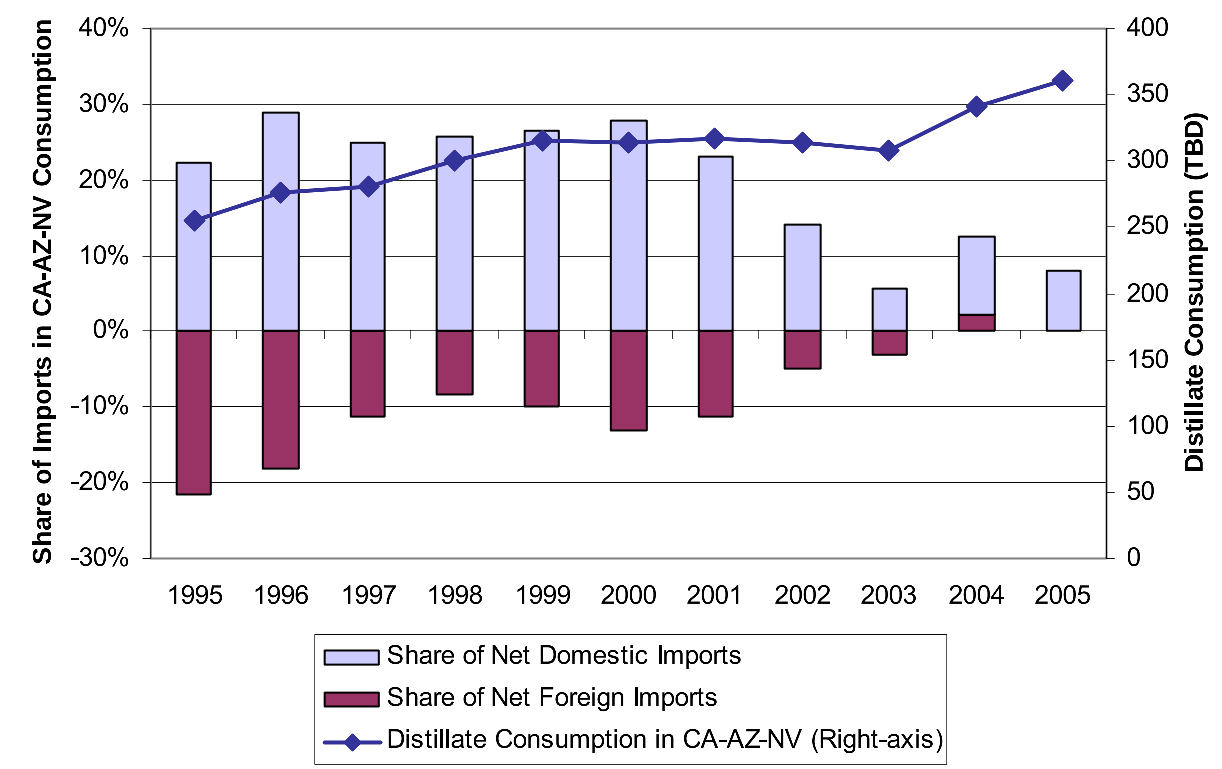
The slight decline in dependency in 2004 and 2005 appears due to slower demand growth and an increase in refinery gasoline yield due to increased unfinished oil processing.

Distillate

In 1995, the net imports of distillates were less than 1 percent of consumption in the three state region. However, a large volume of distillate exports took place to foreign destinations offset by imports primarily from the Pacific North-West. The distillate exports were mainly high sulfur material. Higher distillate consumption outpaced refinery production and the region became more dependent on imports. Exhibit 34 shows the changing patterns over the period resulting in net import dependency of 8 percent in 2005.

The strong growth in consumption of diesel in California and the neighboring states is the primary driver for this change. At the same time import of distillate product form the Pacific Northwest has also declined to about 8% of consumption in 2005 from over 20% of consumption in 1995.

Exhibit 34. Distillate Import Dependency for CA, AZ, NV

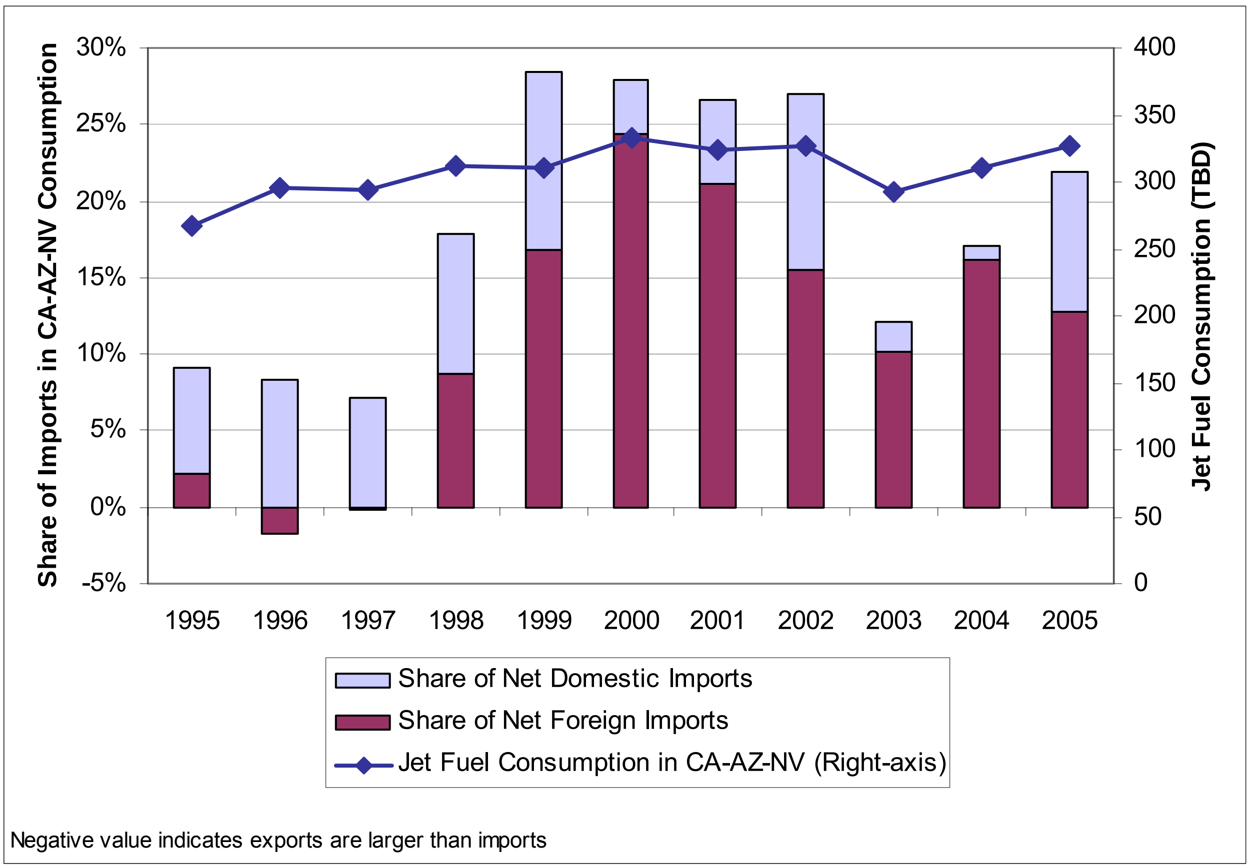


Negative value indicates exports are larger than imports

Source: ICF analysis of data received from various sources.

California, Arizona and Nevada are home to several major international airports and the local refinery production has not been able to meet all the demand in any of the past ten years. Jet fuel consumption has grown by an average 2.3% as compared to 0.5% per year increase in refinery production. Net foreign imports have been generally higher than net domestic imports as seen in Exhibit 35. In 2005, the net import dependency for jet fuel was about 22%, up from 9% in 1995.

Exhibit 35. Jet Fuel Import Dependency for CA, AZ, NV



Source: ICF analysis of data received from various sources.

1.1.5 Stock Levels

Overall inventory levels of petroleum products were examined to identify relative trends in global, U.S., and California stock levels. Data was examined from the Energy Commission's Weekly Fuels Watch Report for California, as well as the U.S. Energy Information Agency (EIA) for national inventory levels. Global stock levels were evaluated from aggregated data from the Organization for Economic Cooperation and Development (OECD).

Exhibit 36 shows the overall trend in gasoline, distillate, and kerosene stocks from the different sources. Data shown is year-end data. Other than an increase in year-end California gasoline levels beginning in 2001, there is no discernible trend in the inventory profile for any segment.

Exhibit 36. California, U.S., and OECD Stock Levels (TB)

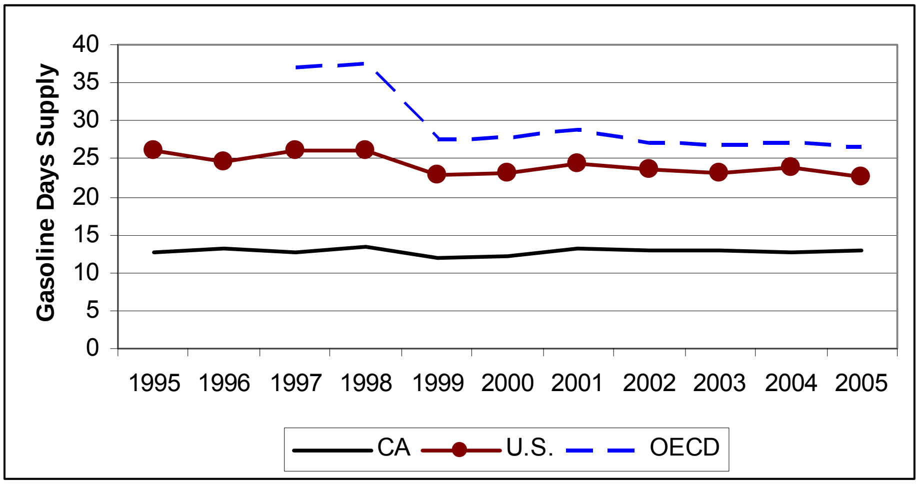
	Finished Motor Gasoline (incl. blending components) Stocks		Total Gasoline Stocks 1	Distillate Fuel Oil Stocks		Middle Distillates Stocks 2	Kerosene-type Jet Fuel Stocks	
	California	United States	OECD	California	United States	OECD	California	United States
1995	11,011	202,326	-----	6,849	130,214	-----	2,229	39,449
1996	11,658	194,985	-----	6,494	126,729	-----	2,357	39,779
1997	11,362	209,775	421,160	5,186	138,427	671,572	2,492	44,009
1998	12,375	215,639	436,344	6,110	156,075	708,193	2,459	44,660
1999	11,353	193,327	389,488	5,308	125,463	624,395	2,531	40,447
2000	11,520	195,852	397,899	5,762	118,027	645,946	2,833	44,409
2001	13,004	209,851	414,933	5,235	144,513	661,501	2,979	41,871
2002	13,002	209,096	395,400	5,568	134,085	639,837	2,825	39,123
2003	13,172	206,827	393,830	5,177	136,542	657,897	2,801	38,767
2004	13,237	217,601	401,115	6,573	126,272	658,651	2,733	40,086
2005	13,473	206,999	393,856	6,106	136,010	691,169	2,927	41,784

1 Total Gasoline includes, Jet Gasoline and Aviation Gasoline
2 Middle Distillates include Gas/Diesel Oil, Jet Kerosene and Other Kerosene. Therefore, there is not a column for OECD in the Jet Fuel stock category. OECD data not available prior to 1997.
Source: EIA Petroleum Navigator, CEC Weekly Fuels Watch Report, and IEA Monthly Oil and Gas Survey

Evaluation of the gasoline inventory on a days supply basis shows that OECD and U.S. inventory levels trended down over the period, with U.S. days of supply declining from about 25 to 23 days (about an 18 million barrel equivalent reduction at constant demand). California days supply was stable, indicating that the higher demand levels over the period were managed with the greater inventory levels shown in Exhibit 37.

The data for California includes gasoline in refineries and several major terminals, as gathered in the Weekly Fuels Watch report. Major pipeline systems in California, including distribution terminals, are not included in this report. As a result, the days supply in California (averaging about 13) is well below the U.S. average.

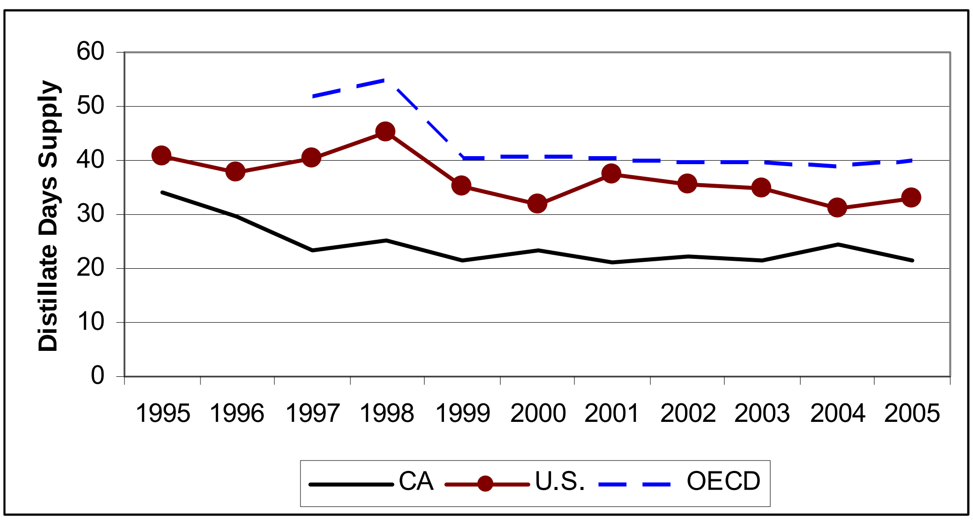
Exhibit 37. California, U.S. and OECD Gasoline Days Supply



Source: EIA Petroleum Navigator Stocks, Product Supplied and Prime Suppliers date, CEC Weekly Fuels Watch Report, CA BOE Taxable Motor Fuels Sales, IEA Monthly Oil and Gas Survey, and IEA Oil Market Report.

Distillate days supply indicate that all three segment areas reduced days supply through the 2000-2001 timeframe, and further reductions have not been subsequently made.

Exhibit 38. California, U.S. and OECD Distillate Days Supply

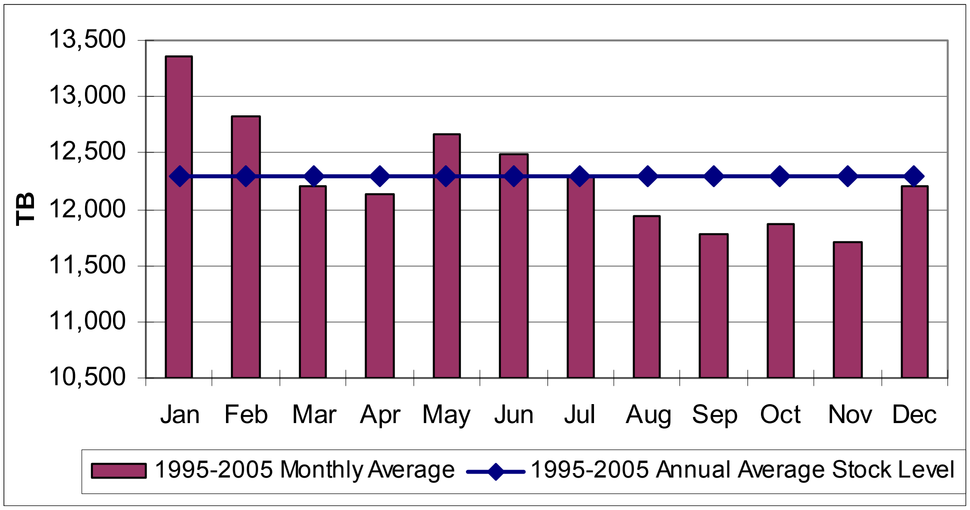


Source: EIA Petroleum Navigator Stocks, Product Supplied and Prime Suppliers date, IEA Monthly Oil and Gas Survey, and IEA Oil Market Report.

Exhibit 39 shows the seasonal pattern for gasoline inventory in California over the past 10 years. The pattern shows gasoline inventory building over the low demand season, drawing because of spring turnarounds and RVP conversion periods, and then re-building in advance of the peak demand gasoline season. There is a consistent draw in inventory through the summer and into the fall turnaround period.

In general, the pattern of inventory fits the overall gasoline demand pattern, and refinery turnaround cycle, as would be expected.

Exhibit 39. Seasonality in California Gasoline Stock Levels



Source: CEC Weekly Fuels Watch Report

1.1.6 Product Tanker Freight Rates

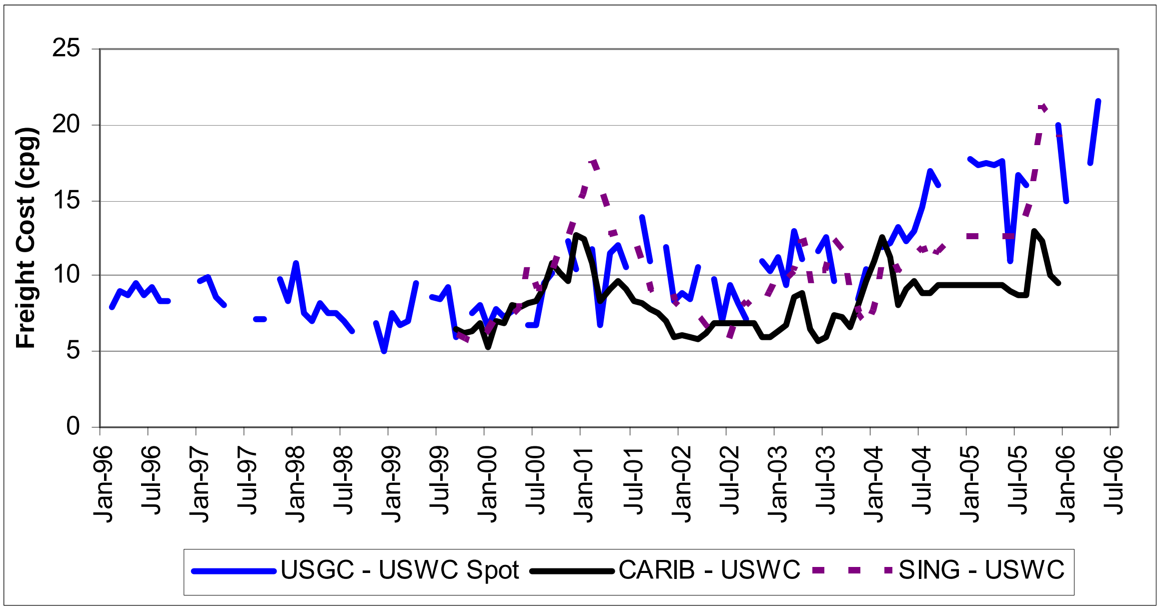
The cost and ability to provide replenishment product into the California market has been expensive and difficult. Product can be moved from domestic sources (both the U.S. Gulf Coast and Washington State primarily) on Jones Act vessels; product can be moved from foreign sources on Foreign Flag vessels. The market for Jones Act and Foreign Flag vessels can be very different since each market has a completely different source of supply.

The Jones Act business for products has a volume of product movement within the West Coast that involves movements from the Northwest into California, and also movements from the San Francisco Bay Area to Oregon. Most of this volume is conventional gasoline. This volume is typically tied up on time-chartered vessels.

The Jones Act business from the Gulf Coast has a mix of time-chartered and spot business. The Gulf Coast to West Coast trade peaked in 1999 with substantial volume of MTBE movements, along with gasoline blendstocks.

In order to compare freight cost changes over time as requested, rates for foreign flag movements from the Caribbean and Singapore to the West Coast were compared to Jones Act vessel rates for spot charters over the study period (see Exhibit 40). The Jones Act rates used were specific cargoes, which were not ratable over the period; however, the comparison of the rates at similar points in time provided a consistent analysis. Analysis of spot rates provides a basis to assess the cost that a refiner or trader would see in evaluating moving discretionary product to the West Coast.

Exhibit 40. Freight Rates to the U.S. West Coast, cpg



Source: Platts Clean Tanker Assessment and Wilson Gillette & Co Jones Act Data

Freight rates to the West Coast have been on the rise since the year 2000 for both Jones Act and Foreign flag vessels. The availability of Jones Act vessels to ship clean products from the Gulf Coast to California is on the decline as Jones Act vessels are gradually retired from the fleet at a greater rate than new Jones Act vessels are constructed. Exhibit 41 shows the specific annual cost range and volume for spot charters on Jones Act vessels:

Exhibit 41. Jones Act Cargo Spot Freight Costs, cpg

TOTAL SPOT DELIVERIES, USGC TO CALIFORNIA				
Year	Volume, MB	LOW	HIGH	AVERAGE
1996	6,808	6.1	11.4	8.9
1997	6,559	5.5	11.4	8.6
1998	4,008	5.0	10.9	7.4
1999	14,265	6.0	18.8	8.3
2000	9,698	6.4	14.1	8.8
2001	5,577	6.8	16.0	11.0
2002	5,023	7.0	11.0	9.3
2003	4,689	7.1	15.0	10.5
2004	6,346	11.2	17.8	13.7
2005	4,730	11.0	20.0	16.9
2006 ytd	740	15.0	22.5	18.1

Source: Wilson Gillette & Co Jones Act Data

The escalation in the Jones Act freight rates mirrors the tightening market for Jones Act vessels as the domestic product fleet continues to be reduced. The relative cost to a shipper to move product from the Caribbean to the West Coast on foreign flag vessels has typically provided a lower cost, if a shipper/refiner can be located to produce either gasoline or blendstocks suitable in quality for use in the California market.

With the supply of gasoline on the West Coast dependent upon movement of blendstocks from USGC refiners to west coast refiners, the increased cost of Jones Act vessels is likely to be sustained. Since the cost of the vessels in fact reflects the tight availability of ships, a larger concern may be the ability to secure the tonnage needed for spot voyages.

1.2 Future Demand and Supply Outlook

1.2.1 Refinery Capacity Growth

Total U.S. refining crude oil processing capacity on January 1, 2006, was 17,317 TBD[15]. The outlook for growth in refinery capacity was assessed from evaluating announcements of major capital projects for U.S. refiners, published construction reports, and by analyzing historical patterns of capacity growth from operational improvements or smaller projects which "debottleneck" refinery capacity.

Over the course of the past year since the hurricanes, U.S. refiners have made a number of investment announcements of major projects for additional refinery capacity for expansion and refinery upgrading capability. In most cases, the refiners have quantified somewhat specific plans, the impacts on capacity, and the year in which the refinery expansion will be operational. The largest of these projects will become operational in the 2009-2010 timeframe. At this time, there are no announced projects by U.S. refiners that would add capacity beyond 2011.

A listing of the projects is shown in Exhibit 42:

Exhibit 42. Refinery Additions Announced as of July 2006

Year In Operation	Refiner	Location	Atmospheric Distillation Capacity (TBD)
2006	Coffeyville Resources	KANSAS, Coffeyville	15,000
2006	Gary-Williams Energy	OKLAHOMA, Wynnewood	20,000
2006	Navajo Refining Co.	NEW MEXICO, Artesia	10,000
2006	Valero Energy Corp.	TEXAS, Port Arthur	75,000
2007	ConocoPhillips	CALIFORNIA, Rodeo & Santa Maria	5,000
2007	Flint Hills Resources	MINNESOTA, Rosemount	50,000
2008	ConocoPhillips	CALIFORNIA, Los Angeles (Carson & Wilmington)	45,000
2008	Frontier Oil Corp.	KANSAS, El Dorado	11,000
2008	Holly Corp.	UTAH, Woods Cross	4,000
2009	ConocoPhillips	ILLINOIS, Wood River	25,000
2009	ConocoPhillips	LOUISIANA, Belle Chasse	40,000
2009	ConocoPhillips	MONTANA, Billings	25,000
2009	Sunoco Inc.	PENNSYLVANIA, Philadelphia	100,000
2009	ConocoPhillips	TEXAS, Sweeny	40,000
2009	ConocoPhillips	WASHINGTON, Ferndale	10,000
2010	Marathon Ashland	LOUISIANA, Garyville	180,000
2010	Motiva Enterprises	TEXAS, Port Arthur	325,000

Source: Company websites & press releases; Oil & Gas Journal Construction reports

This list does not include the grass roots refinery project being planned for Arizona. The project has been negotiating crude supply and pipeline requirements, and has obtained required permitting and a completed engineering design. However, the project has not attracted investors and is not likely to be built and operational in the time frame of this study.

In addition to the crude capacity, there have been several integrated and independent announcements of projects to increase the capacity of U.S. refiners to process heavy and sour crude. Announcements include increases of 218 TBD[16] in coking capacity by 2012, a 9 percent increase over today's capacity. Addition of a coker to an existing refinery enables the refiner to either: 1) produce less residual fuel and more gasoline and distillate, or 2) purchase heavier crude oil as raw material into the refinery by coking the additional residual fuel in the heavier crude, or 3) process more crude oil with full residual upgrading. These projects are attractive because they can lower a refiners' crude cost without depending on incremental product sales to justify the investment. Alternatively, the projects can provide improved margins on existing refineries by either improving product mix (less residual production) or increasing throughput.

The additional crude capacity from the projects listed above will add about a million barrels per day crude capacity by 2011. This does not include annual growth in existing refinery crude capacity from relatively small capital projects, operational changes, and reliability improvements. This annual growth, which has typically been about 1 percent per year on overall U.S. refinery capacity, is a real and substantive factor in the overall growth in U.S. refining capacity in the past 20 years.

For this study, a forecast increase of 0.5 percent annual capacity creep for the U.S. is assumed. The basis for a lower capacity creep outlook is the increasingly more challenging specifications in sulfur levels in gasoline and distillates, and tighter specifications on gasoline blends with refinery production of blendstocks for ethanol blending at terminals. These issues may make it more difficult for the industry to sustain the historical level of performance.

For California, a capacity creep assumption of 0.5 percent annually is consistent with recent history for the major refiners in the state. Exhibit 43 shows the capacity creep for California's major fuel producing refineries from 2001 to current. The growth averages about 0.5% per year.

Exhibit 43. California Refinery Capacity "Creep" Calculation

Company	Location	EIA Capacity 2001 (b/d)	EIA Capacity 2006 (b/d)	Capacity Increase or Decrease (b/d)	Owner in 2001
Big West of California	Bakersfield	66,000	66,000	0	Shell
Chevron U.S.A. Inc.	El Segundo	260,000	260,000	0	
Chevron U.S.A. Inc.	Richmond	225,000	242,901	17,901	
ConocoPhillips Co.	Arroyo Grande (Santa Maria)	41,800	44,200	2,400	Tosco
ConocoPhillips Co.	Rodeo (San Francisco)	73,200	76,000	2,800	Tosco
ConocoPhillips Co.	Wilmington (Los Angeles)	131,000	139,000	8,000	Tosco
ExxonMobil Refining & Supply Co.	Torrance	148,500	149,500	1,000	
Paramount Petroleum Corp.	Paramount	46,500	50,000	3,500	
Shell Oil Co.	Martinez	159,250	155,600	-3,650	Equilon
Shell Oil Products US	Wilmington (Los Angeles)	98,500	98,500	0	Equilon
Tesoro Refining & Marketing Co.	Martinez (Avon)	166,000	166,000	0	Tosco
Valero Refining Co.	Wilmington	78,800	80,887	2,087	Ultramar
Valero Refining Co.	Benicia	129,500	144,000	14,500	
BP West Coast Products LLC	Los Angeles	260,000	260,000	0	Arco
Totals		**1,884,050**	**1,932,588**	**48,538**	
Annual Capacity Growth				**0.50%**	

Source: EIA Petroleum Supply Annual. EIA Refinery Capacity Report, 2001 and 2006.

Exhibit 44 shows the forecast growth in refinery capacity through 2012, based on the announced crude expansions and capacity creep. U.S. capacity grows by about 1,610 TBD in total, and California capacity grows by about 120 TBD. California's growth is through capacity creep and several expansion projects by ConocoPhillips.

Exhibit 44. U.S. and CA Refinery Capacity Growth Outlook, TBD

Year	US Capacity January 1 (TBD)	Announced Expansions (TBD)	Capacity Creep (TBD)	Total Growth (TBD)	US Capacity December 31 (TBD)
2006	17,317	120	87	207	17,524
2007	17,524	55	88	143	17,666
2008	17,666	60	88	148	17,815
2009	17,815	240	89	329	18,144
2010	18,144	505	91	596	18,739
2011	18,739	0	94	94	18,833
2012	18,833	0	94	94	18,927
2006 - 2012		980	630	1,610	

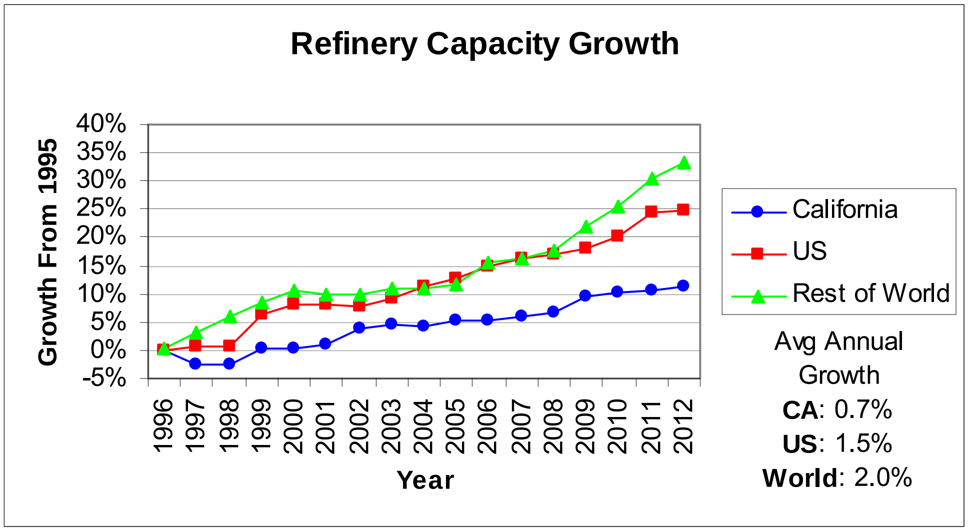
Year	California Capacity January 1 (TBD)	Announced Expansions (TBD)	Capacity Creep (TBD)	Total Growth (TBD)	California Capacity December 31 (TBD)
2006	2,005	0	10	10	2,015
2007	2,015	5	10	15	2,030
2008	2,030	45	10	55	2,085
2009	2,085	0	10	10	2,096
2010	2,096	0	10	10	2,106
2011	2,106	0	11	11	2,117
2012	2,117	0	11	11	2,127
2006 - 2012		50	72	122	

Source: Company websites & press releases; Oil & Gas Journal Construction reports. California data also from Ethanol Renewable Fuels Association.

Potentially, some U.S. refining capacity may be shutdown over this period, the forecast does not include any anticipated shutdowns. Many of the smaller U.S. refineries either supply niche markets without alternative supply options, or provide specialty products such as asphalt or lubes and enjoy good margins. The larger refiners have made investments to stay competitive and meet new regulations such as Ultra Low Sulfur Diesel (ULSD) specifications, and it is not foreseen that shutdowns will occur, at least in the early years prior to 2012.

Globally, there are many announcements of new refinery construction and expansion projects. Global expansions outpace the overall United States and California expansions (see Exhibit 45).

Exhibit 45. Global Expansion vs. United States and California



Sources: Historical: EIA Petroleum Supply Annual. EIA Refinery Capacity Report, and Oil and Gas Journal. Worldwide Refining Survey. Forecast based on ICF Estimates. Note that the EIA did not collect data for the years 1996 and 1998. The refinery counts and capacity for 1996 and 1998 have been estimated using the previous year's data.

The global capacity additions are focused on the Far East and the Middle East, and in many cases represent projects that contain petrochemical integration, which will align well with the growing demands in those regions for both fuel and oil-derived consumer goods.

Overall, average annual growth in the 2006-2012 period for the U.S. and the world is clearly outpacing growth rate for California refining capacity.

Future Production of Fuel Products in the U.S.

The additional refinery capacity is primarily focused in the 2009-2010 period, with capacity creep occurring ratably over the period. In order to forecast both the California and the U.S. projections of fuel product growth over the period, assumptions are necessary to determine the incremental yield. Average yields on crude of gasoline, distillate, and jet fuel have been very stable over the past five years in California and the U.S (see Exhibit 15).[17]

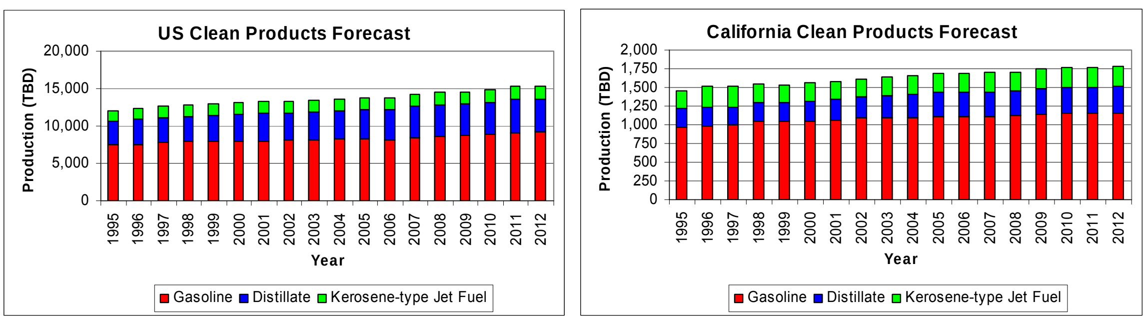
Incremental crude capacity was used to determine additional production growth. Crude run increases were assumed at 92 percent utilization (five year average), and for gasoline, the use of MTBE in 2005 was eliminated from future years. In 2006 and 2007, adjustments were made to utilization to reflect lower utilizations than the five year average. In 2006, the extended impacts of the hurricanes, an intensive turnaround period in the first quarter, and operational problems will make it unlikely that utilization will rise above 88 percent on a full year average. In 2007, it is assumed that utilization will be improved to 91 percent, and then after 2007, a return to utilization levels of 92 percent is assumed.

The analysis assumes that the level of processing of unfinished imports of refinery feedstocks (primarily imported gas oil) will continue at levels seen in the 2004-2005 timeframe. It is assumed that incremental crude runs coupled with heavier crude slates from upgrading projects will keep incremental secondary unit capacity full.

It is understood that the yield of incremental products is consistent with the recent U.S. and California average yields on crude. The reasons are that the yield pattern has been remarkably similar year in and year out, during periods of crude capacity growth. Also, many of the announced expansions are full upgrading expansions, or coking expansions, which will generate similar yields to current refinery results.

Exhibit 46 shows the forward view of refinery production based on these assessments.

Exhibit 46. U.S. and California Production Growth



Source: Historical: EIA Petroleum Navigator Refinery Output, CEC California Monthly Inputs and Outputs. Forecast based on ICF estimates.

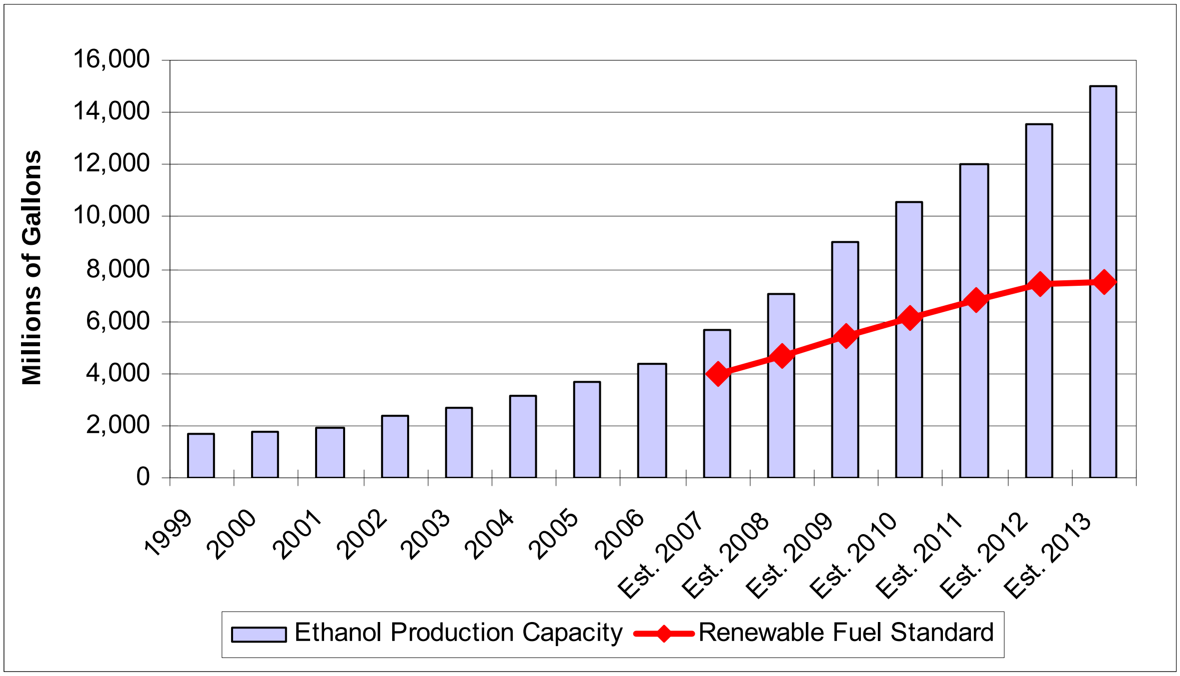
For the U.S. overall, this represents an increase of 889 TBD gasoline and 713 TBD of jet fuel and distillate. For California, the incremental product is about 55 TBD of gasoline and 33 TBD of jet and distillate.

The U.S. number reflects the expansions, plus the return to a 92 percent utilization level. For gasoline, it also reflects the loss of MTBE from the gasoline pool in 2006. For this study, the impact of additional volumes of ethanol blended into the gasoline pool over the period on gasoline production (volatility) and demands (lower mileage) were not considered.

1.2.2 Ethanol Outlook: U.S. and California

Production capacity for ethanol will increase dramatically in the next six to seven years for the U.S. At the beginning of 2005, ethanol production capacity was over 3.6 billion gallons per year, or around 238 thousand barrels per day (TBD); current ethanol production capacity is approximately 315 TBD, which represents an increase of 32.5 percent in 18 months. Plants currently under construction, based on information from the ethanol Renewable Fuels Association (RFA)[18], will add 159 TBD by the end of 2007, an increase of about 50 percent from the present level. This new capacity will result in an ethanol supply capability by the end of 2007 of about 7 billion gallons per year (bgy), which is very close to the 7.5 bgy requirement in the 2005 Energy Act for 2012 (see Exhibit 47).

Exhibit 47. Current and Future U.S. Ethanol Production Capacity (As of Jan. 1 of each year)



Source: Company websites & press releases; Oil & Gas Journal Construction reports; Ethanol Renewable Fuels Association.

By the end of 2012, the level of ethanol production capacity will more than double from the end of 2007 to about 15 bgy, or just under a million barrels per day.

Exhibit 48 shows the ethanol plants that are in the planning or engineering phase, but NOT under construction. Note that the large majority of these plants are planning on start up dates in 2007 and 2008. The additional breadth of ethanol capacity growth implicit in this list of announcements will clearly strain the resources which currently are building and constructing ethanol plants, vessels, process equipment, and so on. In addition, it is certainly possible that for other reasons, a number of these projects may be delayed or halted as they continue to be assessed for feasibility. Consequently, for this study, we have assumed that U.S. ethanol growth beyond 2007 will increase at 2 bgy in 2008 and 1.5 bgy thereafter.

The list of proposed ethanol plants shown does not include any ethanol produced from cellulosic feedstocks (e.g. switchgrass), which may become a significant contributor over this timeframe.

This forecast for ethanol production would result in about 50% of the current U.S. corn crop being dedicated for ethanol production. This is aggressive, but may be achievable with additional dedicated acreage for corn, and the development of cellulosic ethanol plants in the study timeframe.

Exhibit 48. Projected U.S. Ethanol Facilities

Company	Location	Planned Start Date	Status	Capacity (mmgy)
A-1 Ethanol Plus LLC	Roberts, IL	October-2007	Planned	50
Absolute Energy	Saint Ansgar, IA	February-2008	Planned	50
Agassiz Ethanol LLC	Crookston, MN	November-2007	Planned	40
Agri-Ethanol Products LLC	Aurora, NC	November-2007	Engineered	100
Agri-Tech Corporation	Great Falls, MT	November-2007	Engineered	100
Alabama Bio Fuels and Chemicals LLC	Selma, AL	October-2007	Planned	15
Algonquian Ethanol Plant LLC	Princeton, IL	November-2007	Planned	60
Archer Daniels Midland	Columbus, NE	2008	Planned	275
Archer Daniels Midland	Cedar Rapids, IA	2008	Planned	225
Arkenol Incorporated	Elverta, CA	January-2008	Planned	12.5
Baard Renewables LLC	Coshocton, OH	August-2007	Engineered	80
Beemer Energy	Iowa	2008	Planned	110
Beemer Energy	Iowa	2008	Planned	110
BioFuels Solutions	Blue Earth, MN	June-2007	Engineered	110
Bionol Ethanol LLC	Lake Providence, LA	September-2007	Planned	40
Bluegrass BioEnergy LLC	Fulton, KY	September-2007	Planned	55
Bootheel Agri-Energy	Sikeston, MO	December-2008	Planned	100
Borger Biofuels	Borger, TX	March-2008	Planned	100
Buckeye Ethanol LLC	South Point, OH	February-2008	Planned	100
Calgren Ethanol	Pixley, CA	October-2007	Planned	40
Cannon River Clean Fuel	Cannon Falls, MN	March-2007	Planned	80
Cardinal Ethanol LLC	Winchester, IN	December-2007	Planned	100
Cascade Grain Products	Clatskanie, OR	August-2007	Engineered	86
CassCo Amaizing Energy LLP	Atlantic, IA	June-2008	Planned	50
Central Illinois Energy Co-Op	Canton, IL	June-2007	Under Construction	37
Central State Enterprises	Montpelier, IN	Summer 2007	Planned	100-110
Central Texas Ag Development	Cameron, TX	October-2007	Planned	40
Chippewa Creek Ethanol	Havre, MT	October-2007	Planned	40
Crawford County Ethanol	Bucyrus, OH	November-2007	Planned	60
Dakota Renewable Fuels	Valley City, ND	January-2008	Planned	30
Delta Ethanol LLC	Greenwood, MS	September-2007	Planned	30
DeWeese Biofuels LLC	Fairfield, NE	May-2008	Planned	50
Dexter Ethanol	Dexter, IA	January-2008	Planned	50
E Caruso Ethanol	Goodland, KS	October-2007	Engineered	25
E Energy Adams LLC	Adams, NE	May-2007	Under Construction	50
E Energy Auburn LLC	Auburn, NE	October-2007	Planned	50
E Energy Group	Broken Bow, NE	October-2008	Planned	50
Elkhorn Valley Ethanol LLC	Norfolk, NE	March-2007	Under Construction	40
E O H Energy LLC	Greenville, MS	September-2007	Engineered	40
Empire Biofuels LLC	Seneca Falls, NY	October-2007	Engineered	50
Ethanol Grain Processors Inc.	Obion, TN	January-2008	Planned	100
Ethanol Grain Processors Inc.	Washington, KS	December-2008	Engineered	30
First United Ethanol LLC	Camilla, GA	November-2007	Planned	100
Future Fuels Inc.	Toms River, NJ	November-2007	Planned	50
Garden State Ethanol	Woodbury, NJ	August-2007	Planned	40
Gateway Ethanol	Pratt, KS	October-2007	Engineered	55
Genahol Inc.	Phoenix, AZ	November-2007	Planned	7
Glacial Lakes Energy LLC	Aberdeen, SD	November-2007	Planned	100
Greater Ohio Ethanol LLC	Lima, OH	January-2007	Under Construction	54
Great Lakes Ethanol LLC	Adrian, MI	September-2006	Under Construction	40
Great Western Ethanol	Gilcrest, CO	September-2007	Engineered	56
Harrison Ethanol LLC	Cadiz, OH	June-2007	Under Construction	15
Hartford Energy	Hartford City, IN	October-2007	Planned	60
Holt County Ethanol Inc.	Oneill, NE	February-2008	Engineered	84
Illini Bio Energy	Elkhart, IL	October-2007	Planned	40
Illinois Valley Ethanol	Morris, IL	November-2007	Planned	50
Imperial Bioresources LLC	Brawley, CA	November-2007	Planned	50
Indiana Bio-Energy LLC	Bluffton, IN	January-2008	Planned	100
Indiana Renewable Fuels	Argos, IN	May-2008	Planned	100
Intrepid Technology and Resources	Pocatello, ID	September-2007	Planned	40
JBS United Inc.	Royal, IL	January-2008	Planned	100
Jefferson Grain Processors LLC	Jefferson, WI	November-2007	Planned	140
Johnson Grain	Waverly, IL	August-2008	Planned	200
Kalvesta Implement Company Inc.	Kalvesta, KS	September-2007	Planned	30
Land of Lincoln Ag Coalition	Elkhart, IL	October-2007	Planned	20
Levelland Hockley County Coop	Levelland, TX	November-2007	Engineered	30
Liberty Renewable Fuels	Ithaca, MI	November-2007	Planned	100
Lifeline Ethanol LLC	Saint Joseph, MO	October-2007	Planned	40
Lincolnway Energy Cooperative	Des Moines, IA	May-2008	Planned	100
Louis Dreyfus Corporation	Claypool, IN	October-2007	Planned	100
Louisiana Agricultural Finance Authority	Lacassine, LA	January-2008	Planned	41

Company	Location	Planned Start Date	Status	Capacity (mmgy)
Maiz AgriProducts Incorporated	Fowler, IN	November-2007	Planned	50
Marquis Energy	Hennepin, IL	November-2007	Engineered	100
Maryland Grain Producers Association	Baltimore, MD	December-2007	Planned	15
Marysville Ethanol LLC	Marysville, MI	August-2007	Engineered	50
Maui Ethanol LLC	Maui, HI	September-2007	Engineered	7.2
Mercer Energy	Celina, OH	June-2008	Planned	110
Mid America Agri Products/Horizon	Cambridge, NE	June-2007	Under Construction	44
Montana Feed and Fuel LLC	Miles City, MT	November-2007	Planned	40
Necedah Ethanol LLC	Necedah, WI	October-2007	Planned	25
North American Bioenergy Resources	Ulysses, KS	December-2007	Engineered	100
Northeast Biofuels LLC	Fulton, NY	August-2007	Engineered	30
Northwest Ethanol LLC	Hicksville, OH	October-2007	Planned	50
NuFuels LLC	Huntington, IN	November-2007	Planned	50
Oklahoma Ethanol LLC	Enid, OK	October-2007	Planned	50
Olathe Producers Coop	Montrose, CO	October-2007	Planned	40
Oregon Ethanol Corporation LLC	Boardman, OR	September-2007	Planned	30
Oregon Trail Ethanol Coalition LLC	Davenport, NE	October-2007	Planned	40
Pacific Ethanol	Visalia, CA	October-2007	Planned	35
Pacific Ethanol	Boardman, OR	September-2007	Engineered	35
Panda Yuma Ethanol	Yuma, CO	December-2007	Planned	100
Panhandle Energies LLC	Sunray, TX	October-2007	Planned	40
Patriot Energy of Ohio LLC	Mogadore, OH	October-2007	Engineered	55
Patriot Renewable Fuels LLC	Annawan, IL	October-2007	Planned	100
Penn-Mar Ethanol LLC	York, PA	November-2007	Planned	50
Perry Ethanol of Farmers Ethanol LLC	New Lexington, OH	October-2007	Planned	45
Phelps County Ethanol Inc.	Holdrege, NE	February-2008	Engineered	84
Pike Ethanol LLC	Piketon, OH	September-2007	Engineered	15
Prairie Ethanol	Galva, IL	October-2007	Planned	40
Progressive Energies LLC	Platte, SD	October-2007	Planned	18
Putnam Ethanol LLC	Cloverdale, IN	July-2006	Under Construction	100
Renewable Fuels Inc.	Emmetsburg, IA	October-2007	Planned	38
Renewable Power of Missouri	Marshall, MO	August-2007	Planned	30
Renewable Power of Missouri	Cape Girardeau, MO	September-2007	Engineered	30
Renewable Power of Missouri	Carbondale, IL	September-2007	Engineered	30
River Gulf Energy LLC	Buffalo, IA	June-2008	Planned	100
Rocky Mountian Ethanol	Hardin, MT	August-2007	Engineered	30
Rural Energy Marketing LLC	Luverne, MN	June-2008	Planned	20
Rush Renewable Energy	Rushville, IN	October-2007	Planned	60
Savanna Ethanol LLC	Savanna, IL	August-2007	Planned	100
Scoular Company	Plainview, TX	October-2007	Planned	100
SEMO Ethanol Cooperative	Malden, MO	September-2007	Engineered	15
Southern Ethanol Company LLC	Amory, MS	July-2007	Engineered	30
Southwest Iowa Renewable Energy	Council Bluffs, IA	November-2007	Planned	100
Stonic Energy LLC	Menomonie, WI	November-2007	Engineered	20
Summit Ethanol LLC	Hardy, IA	August-2007	Planned	60
Sunnyside Ethanol LLC	Curwensville, PA	October-2007	Planned	40
Superior Corn Ethanol	Superior, IA	October-2007	Planned	50
Swinford Ethanol	Sturgis, KY	August-2008	Planned	60
Tama Ethanol LLC	Tama, IA	January-2008	Planned	50
The Andersons Inc.	Dunkirk, IN	July-2008	Planned	100
Threemile Canyon Ethanol	Boardman, OR	October-2007	Planned	15
Treasure Valley Renewable Resources	Nyssa, OR	August-2007	Engineered	30
United Ethanol LLC	Milton, WI	November-2006	Under Construction	42
US Bioenergy Corp.	Janesville, MN	October-2007	Planned	100
US Bioenergy Corp.	Hankinson, ND	November-2007	Planned	100
US Bioenergy Corp.	Springfield, MN	June-2008	Planned	100
US EnviroFuels LLC	Tampa, FL	October-2007	Engineered	50
US EnviroFuels LLC	Palmetto, FL	November-2007	Planned	40
United Grain Inc.	Scandia, KS	October-2007	Planned	10
Wahoo Ethanol LLC	Wahoo, NE	September-2007	Engineered	30
West Central Ohio Ethanol LLC	Eaton, OH	November-2007	Planned	75
Western Biomass Energy LLC	Newcastle, WY	November-2007	Planned	15
WestPac Fuel	Boardman, OR	November-2007	Planned	50
White Energy	Hereford, TX	October-2007	Engineered	100
Wildwood Ranch Development Incorporated	Joplin, MO	June-2008	Planned	100
Wolverine Ethanol LLC	Grand Island, NE	August-2007	Planned	40
Worldwide Energy Group Corporation	Kaumakani, HI	July-2007	Engineered	7.2
Wright Partners International LLC	Rockford, IL	August-2007	Planned	100

Source: ICF review of various company websites; http://www.impact-net.org/LinkedDocs/%20Ethanol%20Production%20Package.xls (no longer active); ICF validation of list in the previous link.

In California, the current production capacity of ethanol is around 32.7 million gallons per year or about 2.1 TBD. The California figure represents less than one percent of the current U.S. total of approximately 315 TBD. The three operational ethanol plants in California, according to RFA, are the Golden Cheese Company of California in Corona, a Parallel Products plant in Rancho Cucamonga, and—the biggest of the three—a Phoenix Biofuels plant in Goshen. By the end of 2012, planned ethanol plants and those currently under construction in California would increase the state's production capacity around 450 percent to approximately 11.8 TBD (still only around 1 percent of total U.S. ethanol production capacity). Exhibit 49 shows that California has one 35 mmgy (≈ 2.3 TBD) plant currently under construction in Madera and four more plants planned for the next two years.

Exhibit 49. Current and Projected California Ethanol Facilities

Company	Location	Feed	Project Status	Operation Date	Current Capacity (mmgy)	Under Construction or Planned Capacity (mmgy)
Arkenol Incorporated	Elverta	Corn	Planned	1/1/2008		12.5
Calgren Ethanol	Pixley	Corn	Planned	10/1/2007		40
Golden Cheese Company of California	Corona	Cheese whey	In Operation	1/1/1957	5	
Imperial Bioresources, LLC	Brawley	Sugar cane	Planned	11/1/2007		25
Pacific Ethanol	Madera	Corn	Under Construct'n	11/1/2006		35
Pacific Ethanol	Visalia	Corn	Planned	10/1/2007		35
Parallel Products	Rancho Cucamonga	Beverage waste	In Operation	1/1/1993	2.7*	
Phoenix Biofuels	Goshen	Corn	In Operation	9/1/2005	25	

*Capacity amount divided evenly between two Parallel Product plants.
Source: Company websites & press releases; Oil & Gas Journal Construction reports; Ethanol Renewable Fuels Association.

These developments in the ethanol industry should have some positive effects for California in terms of gasoline supply. The new ethanol production capacity in California, for example, should boost the level of internal supply for ethanol blended gasoline from around 5 percent to 20 percent of ethanol requirements by 2012. Clearly, California will still rely heavily on ethanol imports from other states; however, not only is overall U.S. ethanol production going to sharply increase in the near future, but production facilities will also be constructed outside the traditional Midwest corn-belt area and in neighboring states like Oregon and Arizona.

1.2.3 Forecast Demand Growth

ICFI projected growth rates for California petroleum product demand are based on the forecast presented in the Energy Commission's Integrated Energy Policy Report for 2005[19]. Demand for United States as a whole was projected using the growth rates published in EIA's Annual Energy Outlook 2006 (AEO). The AEO projects demand for each product for the United States as a whole as well as nine census divisions. The states of Arizona and Nevada fall under the "Mountain" census division. The projections for demand growth in Arizona and Nevada were made by adjusting the growth rates for the "Mountain" census division published in the AEO to account for the different growth rate that each state has within the division. The adjustment was made by using a ratio of each state's average growth rate from 1995 to 2005, to the average growth rate for the complete "Mountain" division during the same period.

Although gasoline commands a much larger share than distillate or jet fuel in California's petroleum consumption, it has grown at the slowest rate among the three products. This trend is expected to continue with gasoline demand in California projected to grow at an average rate of 1.3 percent from 2005 to 2012. Exhibit 50 shows that gasoline demand in the neighboring states of Arizona (3.5 percent) and Nevada (1.8 percent) is projected to grow at a faster rate than in California, as the population in the metropolitan areas of these states grows rapidly.

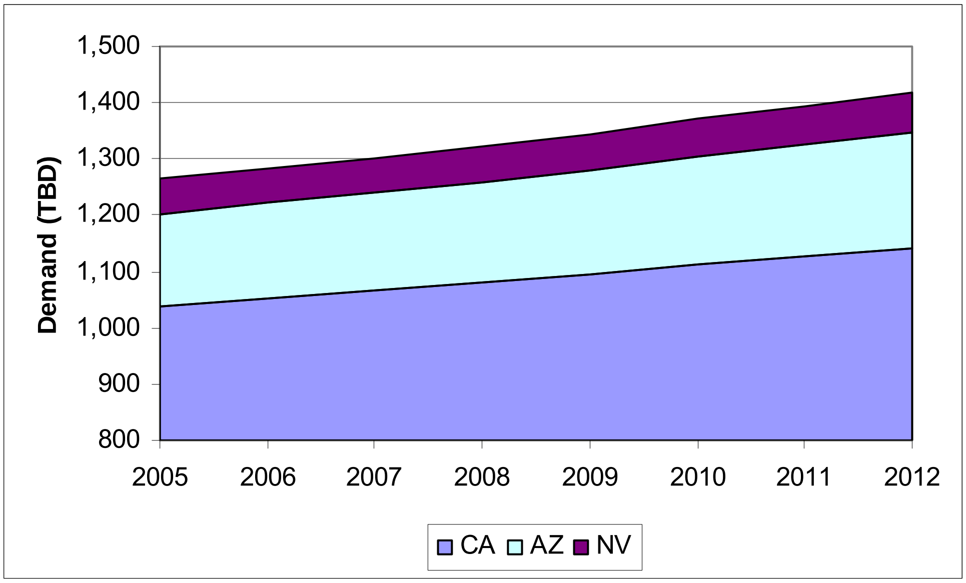
Exhibit 50. Historical and Projected Growth Rates for Demand by Product

Product	Period	CA	AZ	NV	CA-AZ-NV	US
Gasoline	1995-2005	1.8%	3.8%	2.0%	2.0%	1.6%
	2005-2012	1.3%	3.5%	1.8%	1.3%	1.5%
No.2 Distillate	1995-2005	3.5%	5.6%	1.1%	3.6%	2.5%
	2005-2012	2.5%	3.3%	0.6%	2.8%	1.4%
Jet Fuel	1995-2005	2.3%	2.4%	2.2%	2.2%	0.9%
	2005-2012	3.7%	2.2%	2.0%	2.8%	2.9%

Source: EIA Petroleum Navigator Prime Supplier Volumes, EIA Petroleum Navigator Product Supplied, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006.

Exhibit 51 shows that the total increase in gasoline demand for the three states between 2005 and 2012 is projected to be 154 TBD. Gasoline demand growth rate in the United States as a whole is expected to be higher than California but lower than the neighboring states.

Exhibit 51. Projected Demand for Gasoline 2006-2012

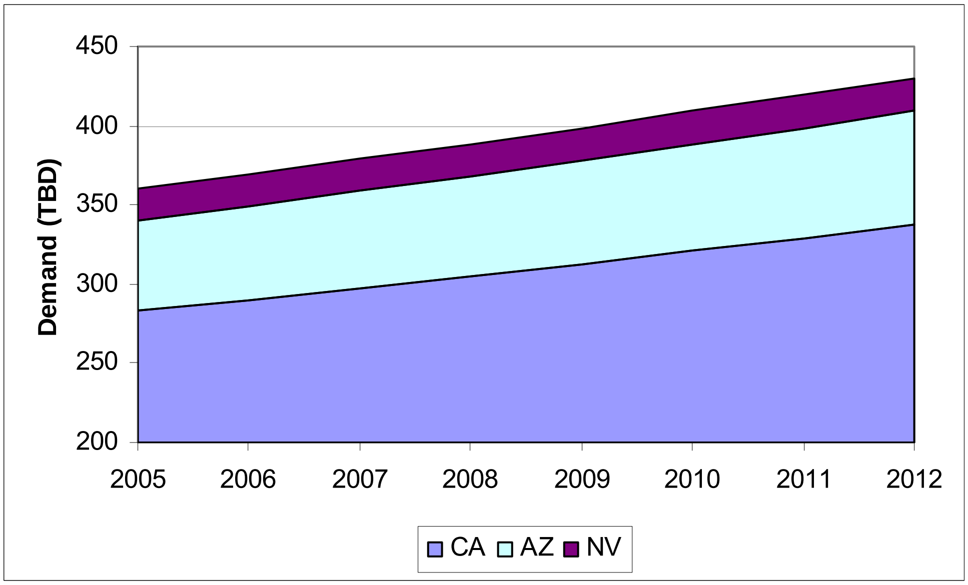


Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report",* EIA Petroleum Navigator Prime Supplier Volumes, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, CEC California Monthly Inputs and Outputs, EIA Petroleum Navigator Refinery Yield.

Distillate consumption in California has grown at an average of 3.5 percent per year during the last 10 years despite declines during the 2001-2003 period. This strong growth is expected to continue and distillate demand growth should average 2.5 percent until 2012 as California's economy continues to grow.

The Interstate-10 freeway originating in Southern California and passing through Arizona is a major freight corridor for goods movements from the West Coast to the Eastern states and down to Florida. The truck volume through California and Arizona on this corridor is expected to increase at an average rate of 3.7 percent per year until 2025[20] and will be a major contributor to the distillate demand growth of 3.3 percent expected in Arizona through 2012. The expected growth in Nevada's distillate consumption, 0.6 percent per year, will be the smallest of the three states. Exhibit 52 shows the combined distillate demand for the three states will increase by 70 TBD over the forecast period. Distillate demand in the United States as a whole is expected to grow by 1.4 percent per year, which is slower than in California and Arizona.

Exhibit 52. Projected Demand for Distillate 2006-2012



Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report",* EIA Petroleum Navigator Prime Supplier Volumes, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006.

In 2005, a total of 326 TBD of jet fuel was consumed within the three states, with California accounting for about 80 percent of the consumption, while Arizona and Nevada had near equal shares of the remaining 20 percent. Jet fuel demand in the three states is expected to grow at an average rate of 2.8 percent per year to 395 TBD by 2012. This growth is only slightly lower than 2.9 percent per year, the rate for the United States as a whole.

Product Exports from CA, AZ, and NV

While California needs to import products to supplement its refinery production and meet the demand in the three states, it actually exports a small volume of product to Oregon and some foreign destinations every year. In 2005, 30 TBD of conventional gasoline was exported from San Francisco to Portland, Oregon[21]. Most of the 13.3 TBD distillate exports is high-sulfur material that will not be able to meet California standards. Another 8.6 TBD of jet fuel is exported to foreign destinations. Exhibit 53 shows the export volumes by product and destination in 2005.

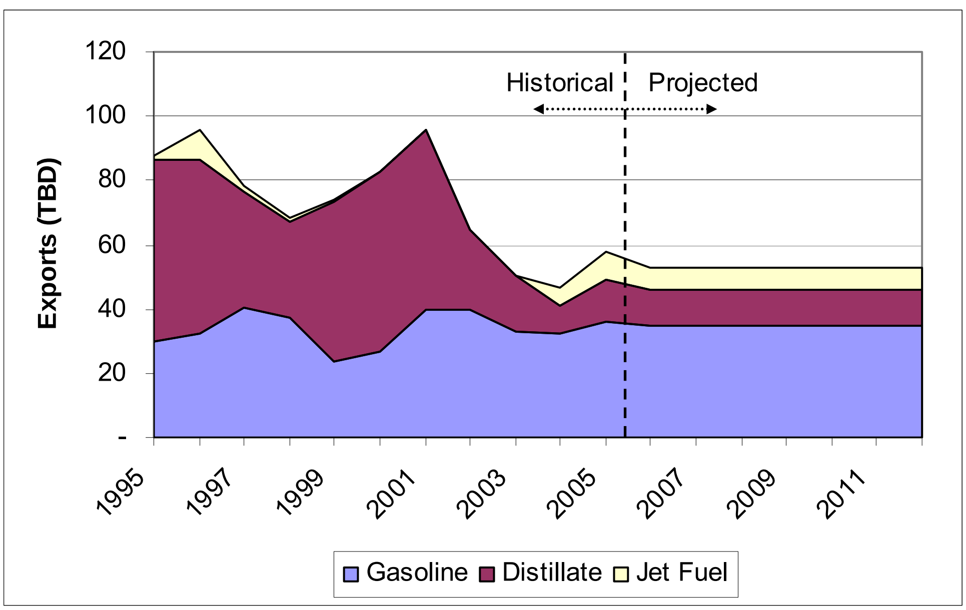
Exhibit 53. Exports of Petroleum Products from California to Oregon and Foreign Destinations in 2005

Fuel (TBD)	Foreign	Oregon	Total
Gasoline	5.9	30.0	35.9
Distillate	8.3	5.0	13.3
Jet Fuel	8.6	0.0	8.6
Total	**22.7**	**35.0**	**57.7**

Source: Foreign exports: EIA, Movements to Oregon – Wilson-Gillette memorandum dated 07/27/2006

Although the export volumes are not consumed locally, they do place demand on California's refineries and the marine infrastructure. We have assumed that some level of products will be exported in the future years and add to product demand in California, Arizona, and Nevada. For gasoline, it was assumed that 30 TBD will continue to be exported to Oregon and another 4.8 TBD will be exported to foreign destination. The foreign export number is the average volume exported from 2001 to 2005 and captures the ethanol transition period for gasoline. For distillate exports, 5 TBD is assumed to go to Oregon and another 6.8 TBD to foreign destinations. These export volumes were estimated as the average volume for the years 2004-2005. The export of jet fuel was estimated in a similar manner as distillate, with 7.3 TBD going to foreign destinations. Exhibit 54 shows the additional demand that exports of these three products will place on California's refining system.

Exhibit 54. Exports of Products from California



Source: Historical data from EIA and Gillette memo. Forecast volumes are projected by ICF.

1.2.4 Estimated Impact on Crude and Product Imports

The supply and demand balance for the U.S. product market overall and California will see significant changes over the next 5-10 years. This section will assess the California regional impact first and then detail the U.S. impact. For California, changes in the crude market as well as products will be examined.

California Crude

For crude, California refineries' demand for crude oil will increase by about 90 TBD over the period based on capacity growth. The additional supply required will need to be foreign imports into California. Assuming ANS receipts are constant with 2005, the incremental foreign crude supplied would need to be about 180 TBD to offset declines in onshore California crude production (See Exhibit 55).

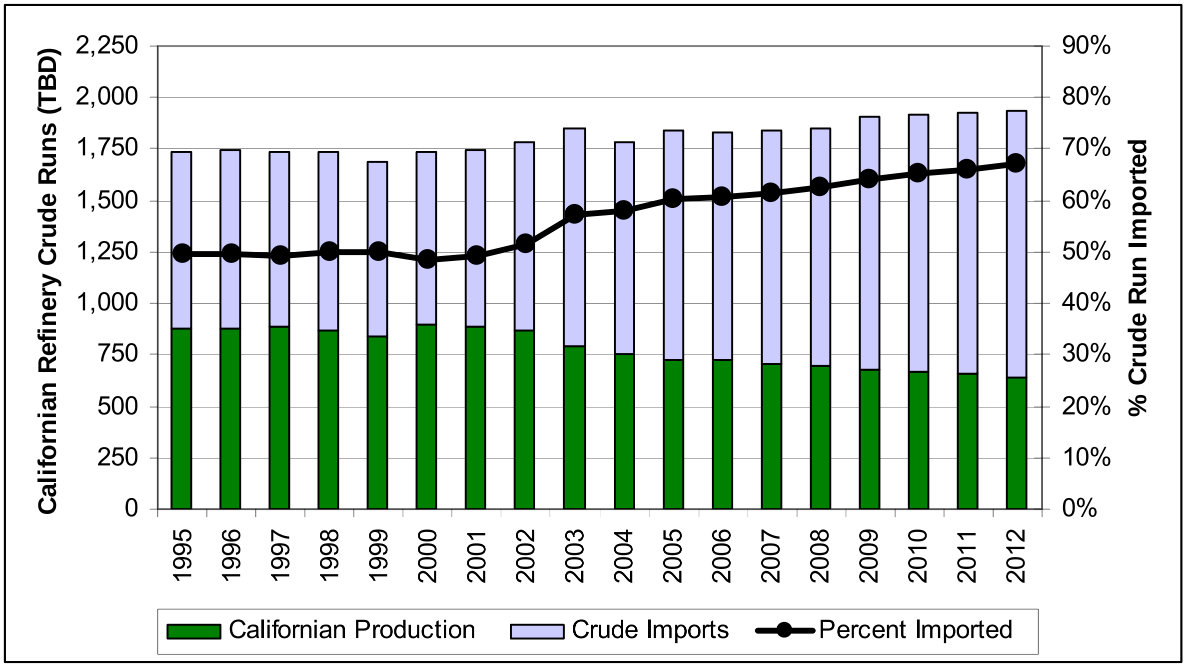
Exhibit 55. California Crude Import Forecast

Year	CA Crude Capacity (TBD)	CA Crude Runs (TBD)	California Production (TBD)	Crude Imports (TBD)
2005	2,005	1,841	729	1,112
2006	2,005	1,831	723	1,108
2007	2,015	1,840	709	1,131
2008	2,030	1,853	692	1,161
2009	2,085	1,904	680	1,223
2010	2,096	1,913	667	1,246
2011	2,106	1,923	654	1,269
2012	2,117	1,932	639	1,294
Change 2005 - 2012	112	91	-90	181

Source: CEC California crude production forecast @2 percent annual decline; ICFI Crude capacity growth from projects and capacity creep @ 91.3 percent utilization (2000-2005 avearge) for California

Overall, California's dependency on imported oil – whether from Alaska or foreign sourced supply – will increase from 60 percent to 67 percent over the period through 2012, as seen on Exhibit 56. Total imported crude supply would be almost 1,300 TBD by 2012.

Exhibit 56. California Crude Import Dependence

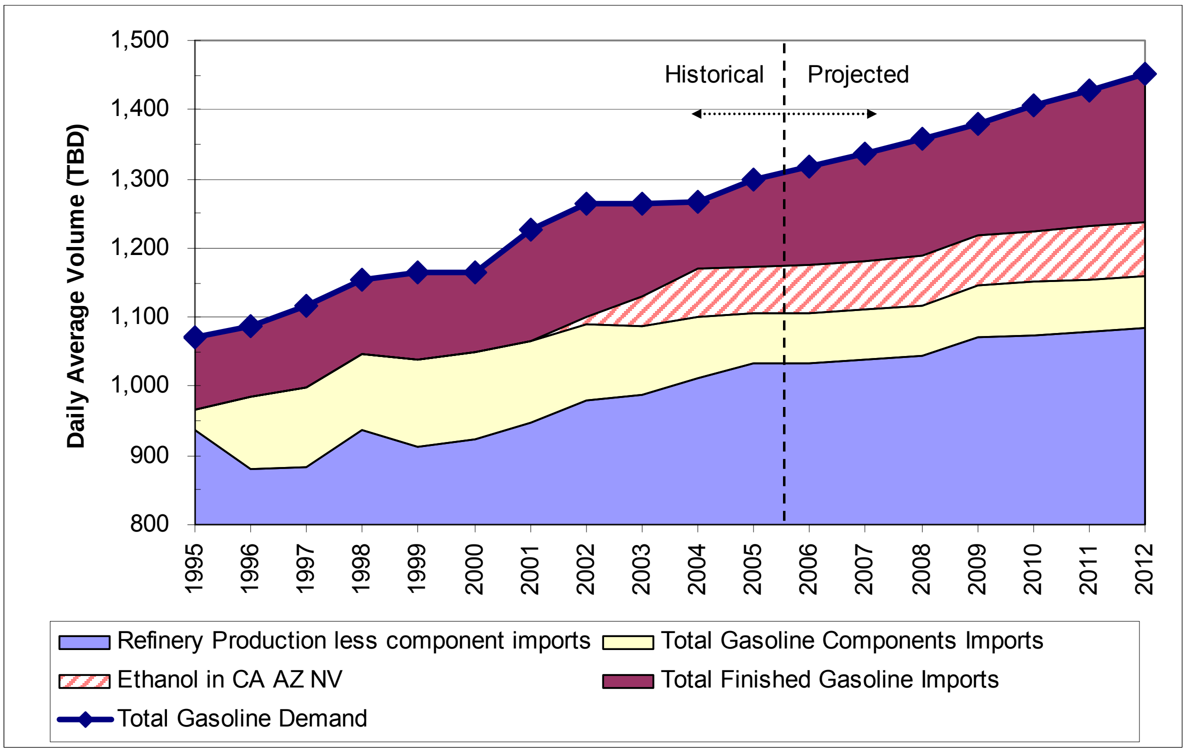


Source: CEC California crude production forecast @2 percent annual decline; ICFI Crude capacity growth from projects and capacity creep @ 91.3 percent utilization (2000-2005 avearge) for California

Products: California and the Arizona/Nevada Market

California's fuel supply balance, as noted earlier, is dependent upon Arizona and Nevada demands as well as California demands. Exhibit 57 shows the trend in gasoline supply in the three-state region over the next six years.

Exhibit 57. Gasoline Supply and Demand: CA, AZ, NV



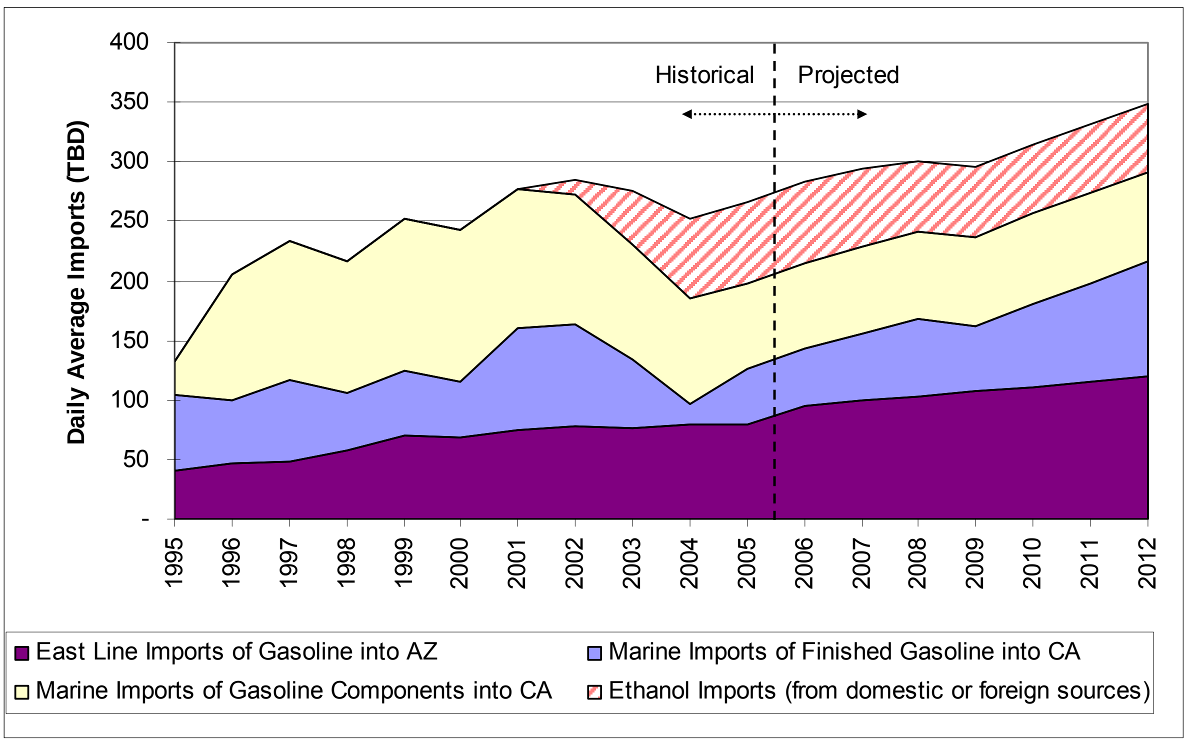
Note: Gasoline demand includes the volume that is exported by California
Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report",* EIA Petroleum Navigator Prime Supplier Volumes, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, Kinder Morgan Pipeline Flows, Wilson Gillette & Co Jones Act Data, ICF Estimates, CEC California Monthly Inputs and Outputs, EIA Petroleum Navigator Refinery Yield.

Over the study period from 2005 to 2012, forecasts show total gasoline demands in the combined three-state market to increase by 154 TBD, or 1.3 percent per year. Additional production of gasoline from California's refining system will increase by 56 TBD, based on capacity announcements and capacity creep. Forecasts show ethanol supply in the region to increase from under 1 TBD in 2005 to 19 TBD in 2012. The net effect will be a larger shortfall of product in the three-state market as time goes forward. The net shortfall will increase from 231 TBD in 2005 to 313 TBD in 2012.

This increase in overall import dependency raises the volume of "outside" supply from 18.3 percent of the region's demands currently to 22.1 percent of demand in 2012. The incremental imports can be delivered into the region either via California ports or the Kinder Morgan East Line, depending on specific grade and volume requirements. As previously indicated, volumes into California must be delivered in marine cargoes, and either meet CARBOB specifications, or be suitable components for blending into the refineries. Product into Arizona must meet Arizona Cleaner Burning Gasoline (CBG) specifications during appropriate seasons.

Exhibit 58 shows the trend in gasoline and component imports into the region in the study period. The chart assumes that incremental Arizona demand will be met by increased volumes on the Kinder Morgan East Line from the Texas/New Mexico region, and that volume on the Kinder Morgan West Line from California will remain at current levels.

Exhibit 58. Gasoline Imports in CA, AZ, NV

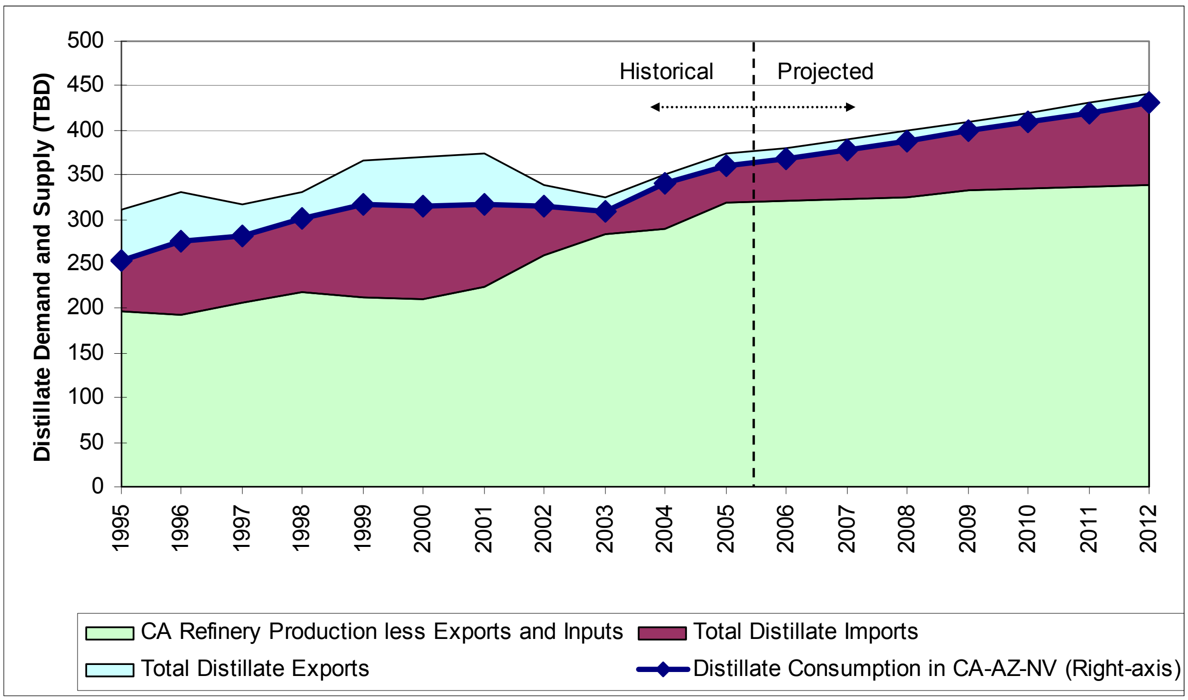


Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report"*, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, Kinder Morgan Pipeline Flows, Wilson Gillette & Co Jones Act Data, ICF Estimates.

This change will further increase California's reliance on gasoline supplies from outside the state. Based on this assessment, and barring any other mitigating actions, California's overall supply-demand balance will continue to be very tight and therefore prone to higher prices relative to the rest of the U.S. None of the current situations which trigger price and supply disruptions appear to be mitigated over the next five year period.

Distillate fuel in the region is primarily diesel fuel. The trend in diesel demand is a very strong growth pattern, with distillate demand in the three-state region increasing from 255 TBD in 1995 to 360 TBD in 2005. This increase has altered the supply/demand balance significantly. Prior to 2002, California and the region had foreign exports averaging about 50 TBD, and at the same time had imports of diesel from foreign sources, the Kinder Morgan East Line, and Washington. With the higher demand growth over the period, the foreign exports decreased significantly through 2002. At the same time, refinery distillate production increased because of higher crude runs, which has reduced domestic import requirements into the region. Exhibit 59 summarizes the changes graphically.

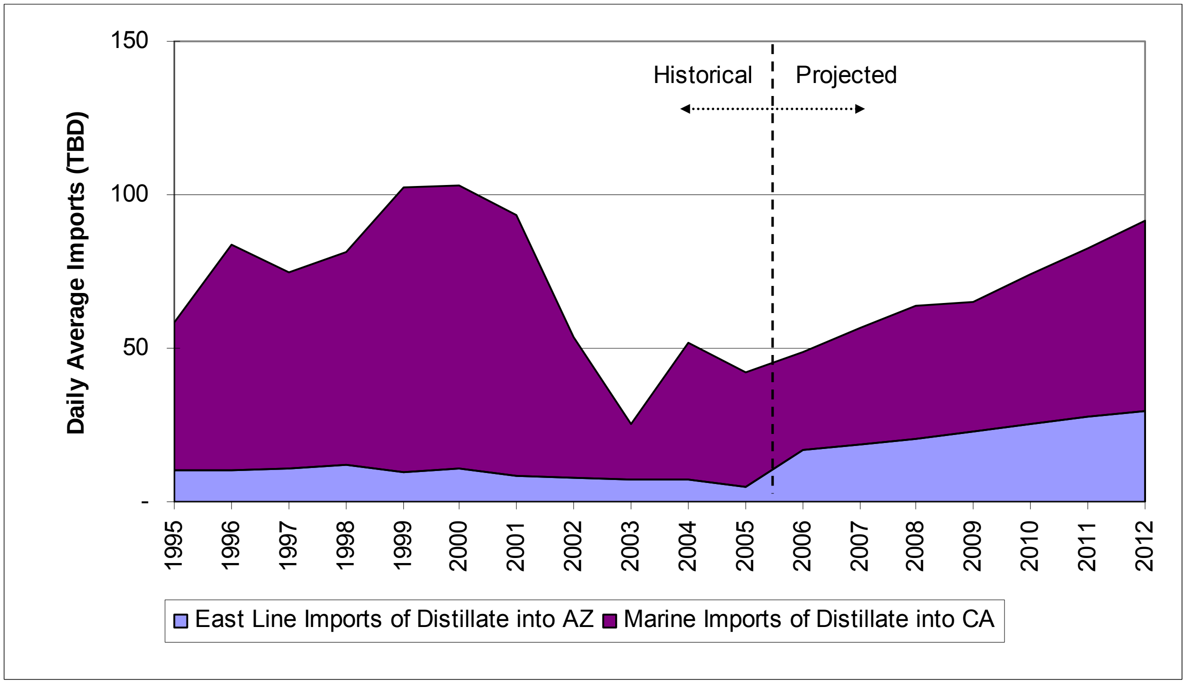
Exhibit 59. Distillate Supply and Demand: CA, AZ, NV



Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report"*, EIA Petroleum Navigator Prime Supplier Volumes, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, Kinder Morgan Pipeline Flows, Wilson Gillette & Co Jones Act Data, ICF Estimates, CEC California Monthly Inputs and Outputs, EIA Petroleum Navigator Refinery Yield.

The impact on net distillate import requirements from 2005 to 2012 is that imports will need to more than double from 29 TBD in 2005 to 80 TBD in 2012. Additional refinery production will provide about 20 TBD of supply; however, the forecast demand growth for the region (just under 3 percent annually) drives total demand up by about 70 TBD (from 360 TBD to 430 TBD). Exhibit 55 shows the relative change in the net import requirements over the period. It is assumed that incremental Arizona demand in this period (15 TBD) will be met by additional shipments on the Kinder Morgan East Line. Net increase in distillate imports through California ports would then be about 55 TBD (which could come from the Gulf Coast, foreign or Washington refiners). Gulf Coast source volume could come via marine, but could also be received from the Longhorn/Kinder Morgan East system. Pipeline volumes above incremental Arizona demand would result in the Arizona Kinder Morgan West Line becoming underutilized.

Exhibit 60. Distillate Imports in CA, AZ, NV

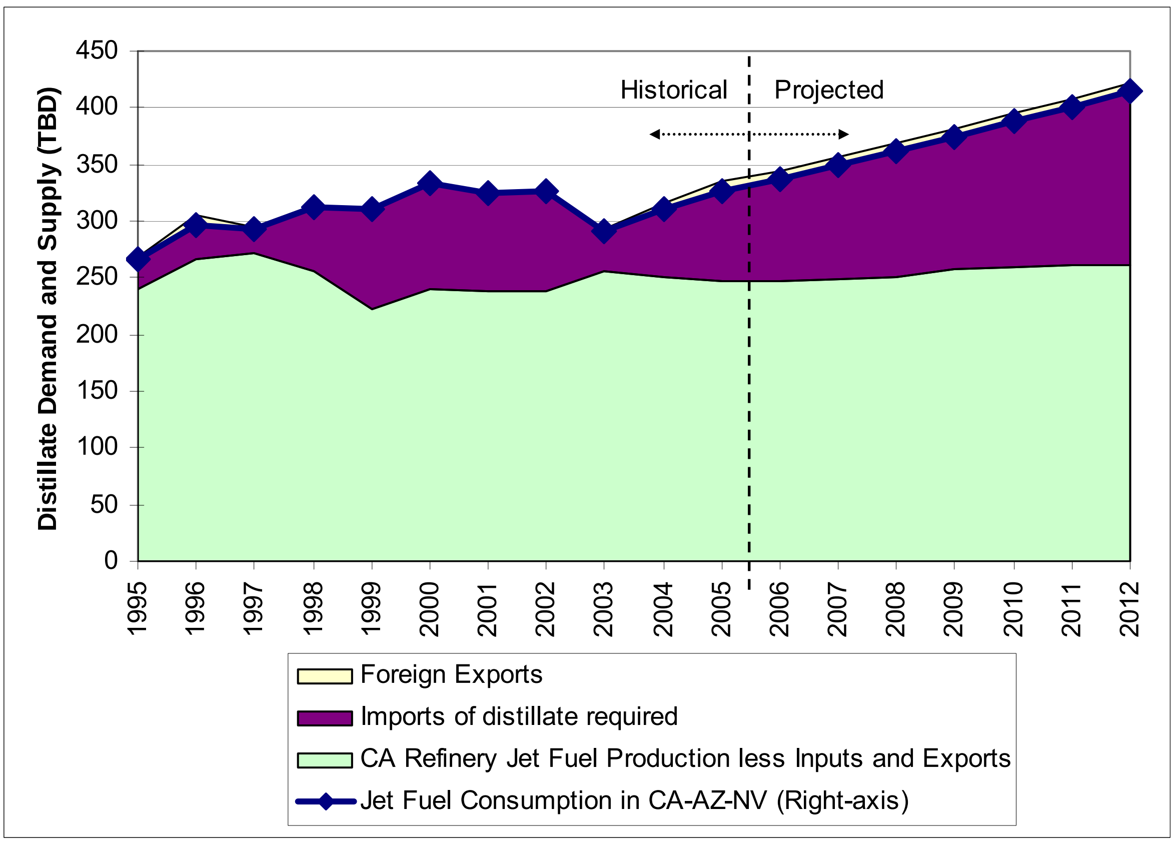


Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report",* CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, Kinder Morgan Pipeline Flows, Wilson Gillette & Co Jones Act Data, ICF Estimates.

Jet Fuel in California

Jet fuel consumption in the three-state region declined between 2000 and 2003, but posted strong growth in 2004 and 2005. The demand is expected to continue its strong growth during the forecast period. Refinery production of jet fuel in California has been growing steadily since 1999 at about 2 percent per year and the East Line imports into Arizona have shown a slow decline. The volatility in demand year after year has been balanced by change in marine imports into California. Going forward, jet fuel demand is expected to grow strongly in the three states, far outstripping the increase in local refinery production. Exhibit 61 shows the projected supply demand balance for jet fuel going forward.

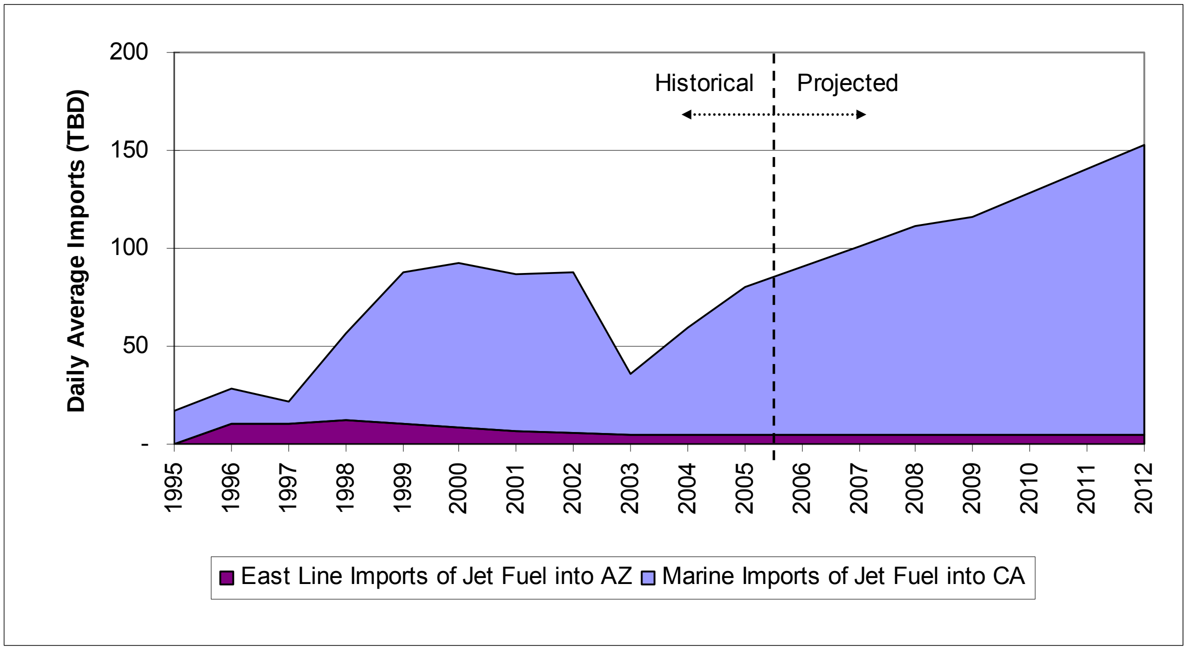
Exhibit 61. Jet Fuel Supply and Demand: CA, AZ, NV



Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report",* EIA Petroleum Navigator Prime Supplier Volumes, CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, Kinder Morgan Pipeline Flows, Wilson Gillette & Co Jones Act Data, ICF Estimates, , CEC California Monthly Inputs and Outputs, EIA Petroleum Navigator Refinery Yield.

With a rapid increase in demand, net imports of jet fuel into the region are expected to grow by 90 percent from 80 TBD to 153 TBD. This increases dependency from 22 percent to 35 percent. Most of these imports are expected to come from marine imports into California, assuming that the jet fuel movements on the East Line stay constant at the 2004-2005 levels (see Exhibit 62). Incentives would likely exist for airlines to become shippers on the Longhorn/ Kinder Morgan East Line into Arizona airports.

Exhibit 62. Jet Fuel Imports in CA, AZ, NV



Source: CEC report: *"Forecasts of California Transportation Energy Demand 2005-2025: In Support of the 2005 Integrated Energy Policy Report",* CA BOE Taxable Fuel Sales Database, EIA Annual Energy Outlook 2006, Kinder Morgan Pipeline Flows, Wilson Gillette & Co Jones Act Data, ICF Estimates.

United States: Overall Market

The forward analysis of refinery capacity growth, ethanol production, and demand growth results in some substantial changes over the next 5-6 years for the overall U.S. market. The growth in refining capacity is primarily focused east of the Rockies. Incremental ethanol production will continue to be focused in the Midwest, although expanding somewhat outside the Midwest.

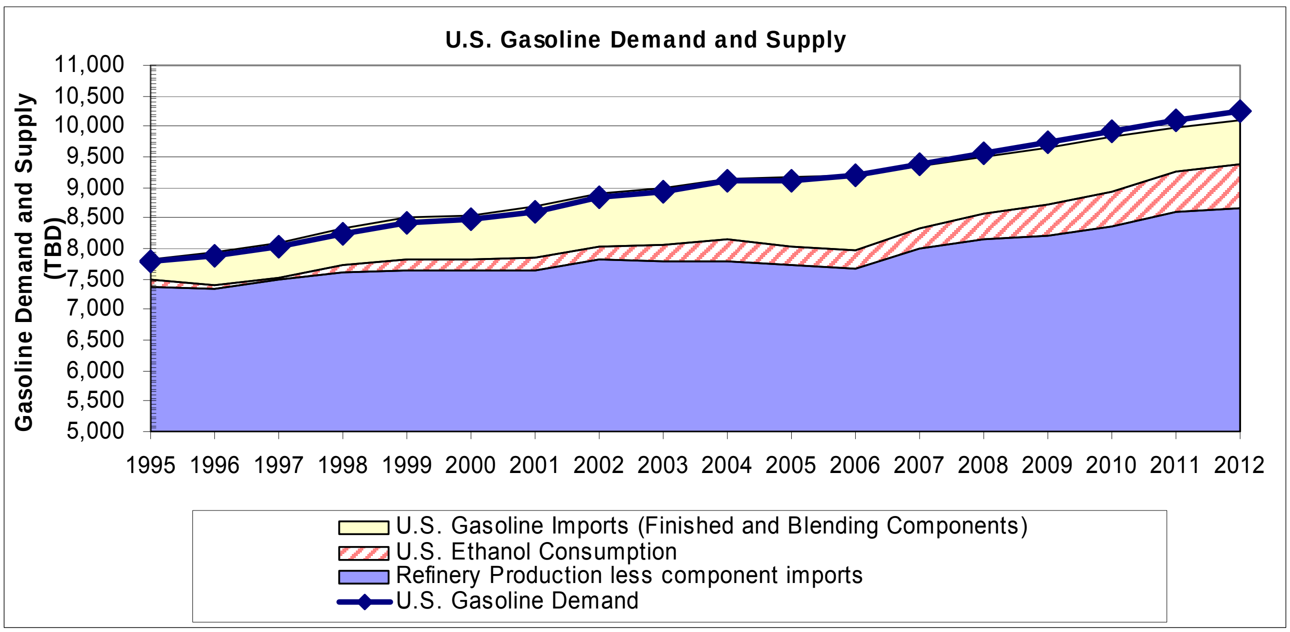
The U.S. product imports in 2005 totaled 1,592 TBD, including 1,129 TBD gasoline (604 TBD finished and 525 TBD components), 317 TBD distillate, and 146 TBD jet fuel (commercial and bonded). Imports of ethanol provided an additional 7 TBD. Imports of unfinished oils (for refinery processing) averaged about 560 TBD.

The U.S. product export volumes are primarily petroleum coke, residual fuel, and gasoline and distillate products exported to local markets such as Mexico, Canada, and the Caribbean. Over time, exports have tended to be fairly consistent year to year, and that pattern is presumed to continue for the fuel products in this study.

Gasoline Imports

Hurricanes in 2005 impacted the import levels that year and into 2006. Refinery utilization levels were depressed in each year compared to the 92 percent average over the 2000-2004 period. As utilization improves in 2007 and beyond, and capacity additions begin to become operational, U.S. imports are forecast to decline. Exhibit 63 shows the reduction in gasoline imports over the period.

Exhibit 63. Trend in U.S. Gasoline Imports, 2005-2012



Source: EIA Form-814 Company-level Imports, EIA Petroleum Navigator Product Supplied, EIA Annual Energy Outlook 2006, ICF Estimates.

The gasoline import level declines from a peak in 2006 at 1,230 TBD to a total of 734 TBD in 2012. Increased U.S. refinery capacity over the period, restoration of utilization rates in 2007 and beyond, and the significant rise in ethanol production cause this reduction. The forecast also assumes that unfinished oil imports will continue at the 2005 level.

Clearly, the ethanol penetration assumption is a key factor in the gasoline outlook. Given the clear identification of a significant number of new ethanol production sites, the drive in the state and federal legislatures to move away from fossil based fuels, and the increased emphasis on flex-fuel vehicles and E-85 use, it is reasonable to assume that ethanol penetration will clearly exceed the RFS mandate. This may occur from economics, additional state mandates, increased penetration of E-85 fuel, or initial production of cellulosic based plants, or a combination of all these factors. The import forecast above assumes that the higher ethanol penetration than the RFS mandate will result in additional gasoline demand than forecast in the 2006

AEO. It was assumed for this study that additional ethanol blended in gasoline above current levels would not impact refinery gasoline vapor pressure requirements (i.e., the conventional gasoline 1 psi waiver for ethanol would apply)

Under the scenario shown in Exhibit 63, the reduction in gasoline imports to the U.S. overall can have a large impact on supply for California, Arizona, and Nevada. The reduced level of imports may take the form of either lower finished imports or lower blendstock imports. The reduced need for imports will impact large local refiners who export to the U.S. (e.g. Irving Oil in Canada, Hess in the Virgin Islands, other Caribbean exporters), as well as parties in Europe or the Middle East who would look to continue or grow exports to the U.S. These parties may have incentive to modify refineries to produce CARBOB gasoline, or produce CARBOB-friendly blendstocks, since traditional outlet demands on the U.S. East Coast may be shrinking. Furthermore, refiners in the Gulf Coast may have incentive to produce Arizona grade gasoline to move into the Longhorn pipeline from Houston to West Texas. This would feed into the Kinder Morgan East system into Tucson and Phoenix, reducing demands on the Kinder Morgan West system into Phoenix, thereby allowing more of the gasoline blendstocks produced by California refiners to be used to create additional volumes of gasoline for use in California.

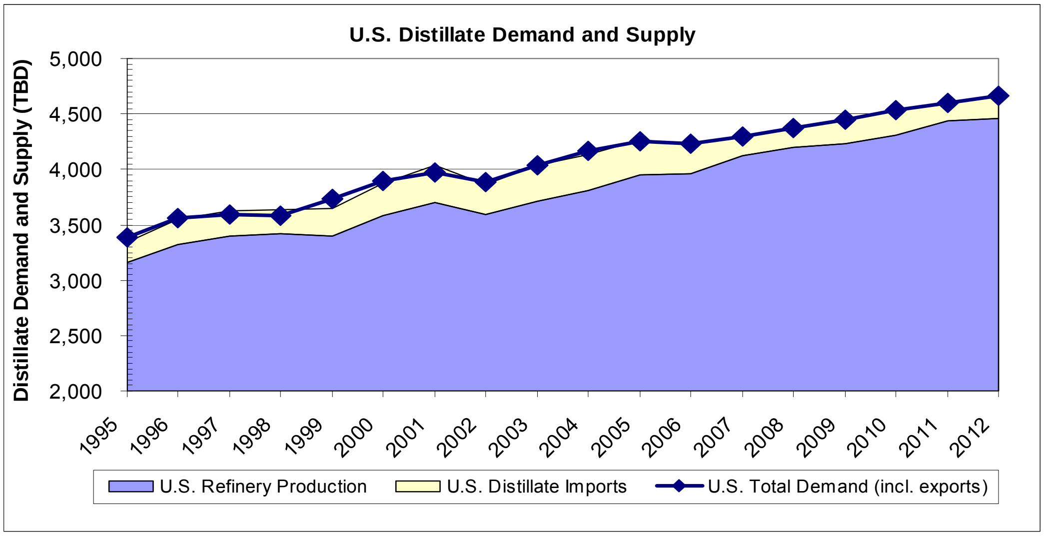
Logistically for California, maximizing volume through the Longhorn/Kinder Morgan East Line route provides the greatest long term benefit. It enables additional supply to be available in California without increasing load on the port infrastructure in Southern California, and sources supply from the largest single aggregation of refining capacity in the world.

This scenario is, however, a world removed from today’s tight market for California and U.S. supply.

Distillate and Jet Fuel Imports

The outlook for distillate import needs for the U.S. is fairly unchanged from the current situation. Exhibit 64 shows that strong distillate growth of about 500 TBD from 2005 to 2012 will be met by the rising refinery distillate production. Net import requirements decline slightly. The distillate growth is about 12 percent over the period, or about 2 percent per year.

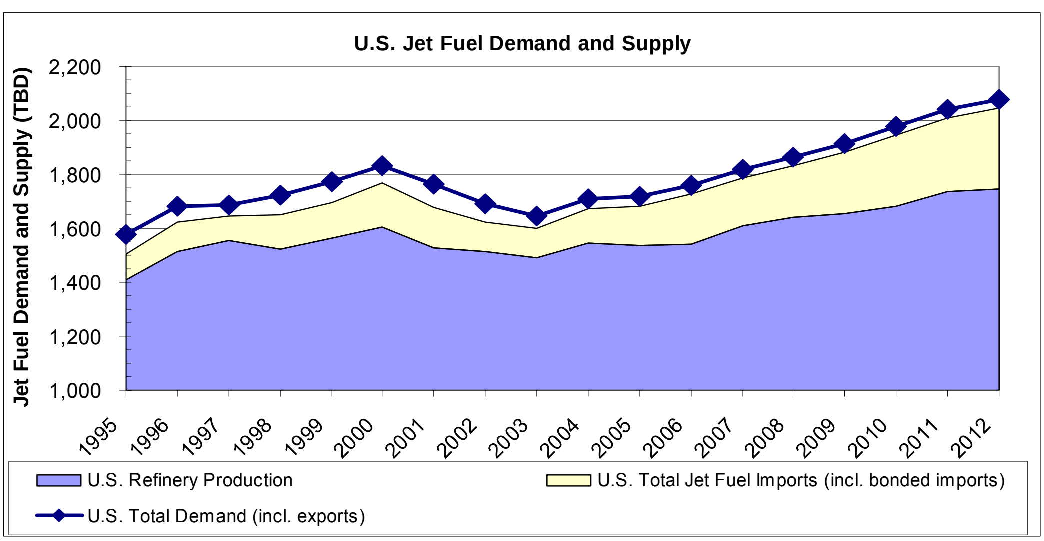
Exhibit 64. Trend in U.S. Distillate Imports



Source: EIA Form-814 Company-level Imports, EIA Petroleum Navigator Product Supplied, EIA Annual Energy Outlook 2006, ICF Estimates.

The jet fuel balance shows a greater and increasing dependence on imports than distillate. Jet demands are projected to increase by over 20 percent from 2005 levels, or an increase of about 355 TBD. The refinery production forecast increases as well, but only by about 208 TBD, resulting in an increase of about 147 TBD of jet fuel imports. About half of this growth in imports will be required to satisfy California's consumption.

Exhibit 65. Trend in U.S. Jet Fuel Imports



Source: EIA Form-814 Company-level Imports, EIA Petroleum Navigator Product Supplied, EIA Annual Energy Outlook 2006, ICF Estimates.

1.3 Key Supply Constraint Factors

As the overall analysis shows, California is projected to remain in a gasoline supply situation which requires a substantial supply of gasoline, gasoline components, and ethanol to be orchestrated into the state to meet consumer demands across the entire California-Arizona-Nevada market. Projections noted in the prior section indicate that California's net dependence on imports of gasoline and gasoline blendstocks could grow from 231 TBD in 2005 to 313 TBD in 2012, or 82 TBD. This is roughly 22 percent of regional gasoline supply across the three-state market in 2012 versus 18 percent today. Forecast increases in jet fuel demand and diesel demands over the same period add a net additional 124 TBD of imported fuel.

The situation that exists in California has been in place for a number of years, since the introduction of California reformulated gasoline in 1996. In order to manufacture gasoline within the regulated specifications, California refiners were required to purchase and blend significant volumes of MTBE and, to a lesser degree, blendstocks into the refinery to produce the new gasoline. As overall gasoline demands increased, California refinery production increased, but primarily because of increased imports of MTBE and gasoline blendstocks into the refineries.

The existing petroleum distribution network in California has a number of barriers to efficient supply replenishment. These barriers have been noted in many other reports to and from the Energy Commission in recent years. The salient issues include the following:

Geography

California is physically isolated from the primary refining center in the world (the U.S. Gulf Coast) by a significant number of days, as well as economics. Vessel transit times from Gulf Coast loading to discharge in Los Angeles can be two weeks, including Panama Canal transit time. While this replenishment cycle can be dependable for time-chartered, ongoing movement of products, spot replenishment needs to handle unscheduled supply disruptions can require a considerable amount of additional time to arrange a supplier, and a Jones Act vessel.

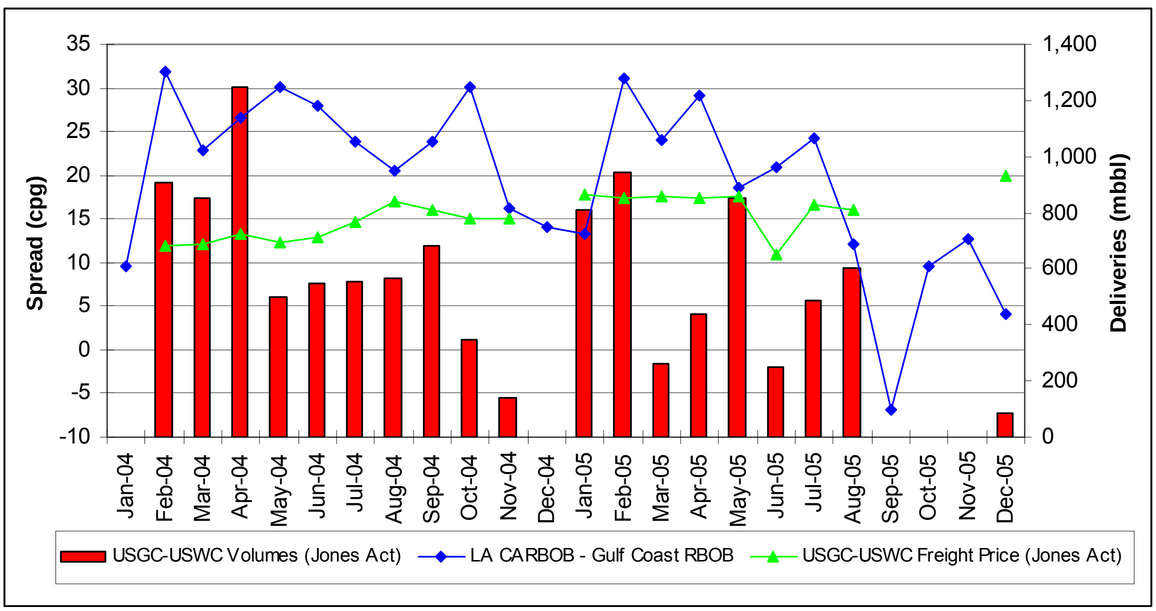
Furthermore, while the U.S. East Coast has “natural” gasoline import sources in Canada, the Caribbean, Europe and Venezuela that can meet (for the most part) East Coast quality requirements, California is much further removed from foreign product supply. In many cases, disruptions in refinery operations on the West Coast cannot be quickly responded to, resulting in spot market prices that can increase quickly and dramatically when outages occur.

Quality

California is also "quality" isolated from the rest of the United States. The unique requirements of CARBOB gasoline versus the RBOB grade manufactured for many markets in the U.S. eastern markets makes it very difficult for a Gulf Coast refiner to load a vessel on a prompt basis to supply California during a disruption.

The implications of the quality issues and the geography issues can best be exemplified by Exhibit 66 below. This graph shows where CARBOB prices exceeded RBOB pricing in the U.S. Gulf Coast by 25 cpg or more for most of 2004 and a good part of 2005 before the hurricanes. During this period, Jones Act vessels were chartered at actual contract rates averaging about 15 cpg, well below the 25 cpg market differential. In this time frame, volumes shipped on Jones Act vessels were very strong, since shippers (refiners or traders) had a 10 cpg "arbitrage" benefit, assuming that the refiner or trader could produce California quality gasoline or blendstocks under the arbitrage. Notably, when the "arbitrage", or market spread, fell to the 15 cpg level in November and December of 2004, there were ***no*** movements on Jones Act vessels (in other words, the "arb" closed).

Exhibit 66. Spot PADD 3 to PADD 5 Movements versus Market & Freight Pricing



Source: Jones Act Prices and Volumes: Wilson Gillette & Co Jones Act Data; Other Prices: EIA Petroleum Navigator Spot Prices.

During the fourth quarter of 2005 (post hurricanes), there was physically no available excess gasoline product on the Gulf Coast to move. The important issue in this analysis is that in the periods of a high arbitrage in 2004 and 2005, the volume of gasoline moved to take advantage of a wide price spread, *was not even higher.*

Jones Act vessels appeared to be available, and while freight rates increased a bit over the time frame, the price spread remained wide. Therefore, it appears that the ability of Gulf Coast refiners to “take advantage” of much higher spot prices in California – even when the situation exists for an extended period – may be limited by the ability to provide CARBOB quality gasoline or blendstocks, or the scarcity of excess storage tank capacity to unload gasoline in the Los Angeles Basin.

Refinery Capacity Growth

Refinery capacity growth in California has lagged the rest of the United States, even in the area of capacity creep (California gains from capacity creep since 1995 have averaged 0.5 percent per year versus 1 percent for the U.S. overall). California refiners have spent a large amount of money to invest in capability to produce CARBOB quality gasoline, ultra low sulfur diesel and to meet other air, water, and stationery source emissions requirements. Data on both crude utilization and input of unfinished stocks to load refinery secondary units indicate that refiners pushed the equipment to maximize operational throughput in 2004 and 2005.

Despite these capital expenditures and operational improvements, there continues to be minimal announcements of significant refining investment in California. Other then the ConocoPhillips Los Angeles refinery expansion in 2008 (about 45 TBD), no other announcements have been made since last fall.

As noted earlier, issues such as required environmental offsets. permitting delays and uncertainty of approval, port authority actions to restrict/remove or relocate tankage which would be needed for incremental crude or product imports, very stringent product quality requirements, and so on conspire to add significant investment risk to refiners considering expansion.

With gasoline, diesel, and jet fuel demand growth of as much as 311 TBD forecast between 2005 and 2012 in the three state region, enabling additional “local” production should be a priority for California.

California Distribution Infrastructure

California’s distribution system is like an automobile with no shock absorbers. With a system spread over a very wide geographic area, high growth demand at the extreme delivery locations, increasing emphasis at ports on container vessels and initiatives to re-locate oil terminal sites, and growing need to import products, there are fewer and fewer degrees of freedom to operate.

Permitting requirements in California and the multiple entities required for approval make it difficult to make changes to the distribution system in a timely manner and to allow a reasonable return on investment.

Barriers to Change

None of the above issues should be a surprise. These observations have been repeatedly made over the past five years (and longer in some cases) by representatives of the Energy Commission, the oil industry, independent consultants, and others. The number of supply and price disruptions that have occurred indicate these observations have not been without merit.

Government entities face a significant challenge is getting private citizens and industry officials to address a clear and visible threat to the state’s future economic health. While many of the constraints above have been identified before, and presented with recommended actions and ideas for improvement, virtually nothing of substance has been implemented in the past few years. This situation presents a serious barrier to enabling the kind of change needed to resolve the physical supply barriers presented above.

The ability to drive the kind of improvements needed to increase supply in California, preserve the environmental gains already achieved, and mitigate the exposure to supply and price disruptions will require strong measures and collaboration between industry and state and local parties.

In summary, the issues impacting fuel supply and prices in California appear to be driven by a fragile supply chain and aggravated by long and time-consuming replenishment alternatives, complex gasoline quality requirements for parties wishing to enter or supply the market, lengthy permitting process for infrastructure improvements, and pressure to reduce or relocate tankage essential to the continuous supply of fuel products to consumers. This situation is extremely difficult for consumers and businesses facing higher prices than other regions of the country, people impacted when supply disruptions threaten both price and ability to secure fuel, and for the oil industry operating and investing in an uncertain and politically charged market.

1.4 Potential Considerations to Improve Supply

As noted above, the overall fuel situation in California, Nevada, and Arizona is significantly impacting citizens and business in this market. The primary reasons for the disruptions and the price separation from the rest of the U.S. market are a combination of the issues noted above, and there is no one solution that will provide substantive mitigation of the problem in the short term. None of the recommendations below, or other worthwhile recommendations that may be proposed can be independently implemented without collaborative efforts between industry and multiple levels of state and local government. Consequently, the first recommendation is:

Organize to Achieve Results

All parties should recognize that the product supply problems existing in California are real and substantive, and the result of several factors that have developed over the years. Leadership and accountability must be provided for each initiative so there can be consensus on the multiple tradeoffs that may be necessary to enable beneficial change.

Ongoing tracking of progress for each initiative must be reported to the Governor and the public on a regular basis. Ideally this would be via an independent entity such as the Energy Commission. The initiatives should be agreed among impacted parties with accountability for actions to address the issues on a priority basis.

The specific recommendations below are in many cases similar to recommendations made in the past few years to address the supply infrastructure in California. Other recommendations may also be appropriate to mitigate the supply issues. However, unless there is some compelling oversight and direction provided to make substantive improvements actually happen and become implemented, petroleum product supply in California can only deteriorate.

The recommendations below include initiatives that can make a specific contribution to solving the problem, and others that provide an improved business or social environment for investment, that would contribute to solving the problem. These recommendations require substantial additional research to fully evaluate the benefits and concerns of each initiative. However, they align with the market assessment in this report and merit additional analysis. The recommendations are as follows:

Do Not Harm the Current Petroleum Import and Distribution Infrastructure

The report analysis indicates that the supply of petroleum products into California is a significant portion of the state supply. Moreover, it is the primary source of replenishment in the event of refinery outages, or other disruptions which could impact supply and costs to citizens. Previous studies by the Energy Commission have cited the critical need to protect the infrastructure, particularly related to port activity.

Potential actions by Port Authorities to not renew leases of petroleum distribution terminals, or to relocate petroleum distribution terminals, will have a detrimental impact on the petroleum market in California, and potentially impact Arizona and Nevada as well. The high gasoline demand level in this region, and the relatively low system inventory, require a careful and steady management of petroleum fuels into, within, and out of the state. The supply chain is fragile as it currently operates. Actions which undermine the ability to ratably and economically sustain supply to consumers will lead to more frequent and more extended disruptions.

Actions should be taken immediately to freeze any project or action which would result in the closure or relocation of petroleum distribution assets, until a thorough assessment of the impact on petroleum supply can be established.

In 2004, the State objected to the proposed closure of the Shell Bakersfield refinery on similar issues (i.e., the potential harm to citizens with the reduced supply of petroleum products). The port issue can be more significant since the volume of imported fuel is over 20 percent of the state and regional supply.

This particular issue is difficult, since there are conflicting priorities with Ports' legitimate desire to expand business in the most profitable manner. It is an example of an initiative where tradeoffs may be necessary, and other parties may be impacted as part of the resolution (for example, if a terminal is relocated to another area).

Implement Recommended Changes in the Permitting Process

Over the past few years, the Energy Commission and consultants have conducted several studies evaluating methods to improve and streamline the permitting process with numerous recommendations. Little has been implemented despite evidence from the oil industry[22] that permitting processes have had a significant effect on the progression of refinery and infrastructure projects.

With the extensive levels of permitting requirements identified at multiple layers of the government in California, the issue has been identified[23] as primarily one of process issues rather than compliance with rules. Since the permitting process has the potential to delay projects adding to the existing infrastructure, it is imperative that improvements identified be implemented as soon as possible. An improved permitting process does not guarantee projects will be developed, but it does assure potential investors that there will be no undue delay in the project timeline.

The recommendations to streamline the permitting process involve a broad number of parties at the state, local, and Federal level, and will be a challenge to implement in a timely manner. Again, visibility of this effort at the highest level of state government is essential to ensure that process improvements are made consistent with maintenance of strong environmental and social impact oversight.

Implement an Aggressive Program to Market E-85 in California

Currently there are only a couple of E-85 fueling stations in California. E-85 is an 85 percent ethanol/15 percent gasoline blend that requires a flexible-fuel burning vehicle to optimally use the fuel. The long term outlook for ethanol supply presented in this paper is strong. It forecasts California to continue to depend on ethanol imports to meet CARBOB gasoline quality. The existing supply chain to move ethanol into California from the Midwest is via Burlington Northern's ethanol unit train from the Midwest to Lomita. This delivery method has proven reliable since the MTBE phaseout.

E-85 increases gasoline supply available to consumers. Although ethanol has a lower BTU content (energy content) than gasoline, one gallon of E-85 can displace about 0.75 gallons of gasoline from fossil fuel.

Major automakers are developing flex-fuel vehicles and E-85 is marketed in the Midwest already. E-85 has roughly 25-30 percent lower mileage than gasoline with no ethanol, but it represents a very real option to increase supply of transportation fuel in California. Current ethanol prices may not make E-85 economic; however, the large increase in ethanol production in the U.S. may soften prices in the future. E-85 automotive emissions are is an additional area that should be evaluated.
There are problems which may need to be addressed; however, the existing ethanol supply chain, growth in U.S. ethanol production, and base import levels of gasoline and components in California are significant drivers to consider how to ramp up E-85 as an automotive fuel in the state. *California should evaluate the steps needed to support significant growth in E-85 usage in the state. An initial goal could be an assessment of the environmental impact, auto industry position, and logistics needs within six months.*

Evaluate and Implement Modifications to Gasoline Quality Specifications

California's current gasoline specifications are the most stringent in the United States. The degree of difficulty to produce CARBOB gasoline is clear, since very few cargoes of CARBOB gasoline has been imported to California either from foreign, U.S. Gulf Coast, or U.S. Northwest sources, despite significant economic incentives on numerous occasions. Imports have typically been gasoline blendstocks, which must be imported and processed through refinery blending tankage to integrate with other refinery components to produce CARBOB for pipeline shipment. This process ties up refinery tankage in the "reblending" process, and therefore exacerbates the infrastructure issue. Imports of finished CARBOB could be integrated into the pipeline and terminal system more readily.

The need to control automotive emissions to protect the environment and public health is not in question. However, if a greater number of foreign or Gulf Coast refiners could produce a finished CARBOB product, the supply chain into California becomes less fragile. Refiners in those markets have little incentive to upgrade refineries to produce CARBOB quality since the need for any one refinery to supply CARBOB on an ongoing basis is not likely. However, if refiners or blenders could have the flexibility to provide a near-CARBOB quality gasoline (for example, RBOB with the lower California RVP), and pay a quality premium to the state, it may provide a greater incentive for parties to take advantage of the price spread to the West Coast.

This recommendation requires some tradeoff considerations as well. The intent would be to minimize any environmental concessions, so the matter would need further study. Furthermore, California refiners could oppose market changes that may undermine their investments in California refineries producing CARBOB.

Create Incentives to Exploit Potential Changes in Supply and Demand East of the Rockies (EOR)

The study indicates that the increased refinery capacity East of the Rockies (EOR), coupled with ethanol production growth, will reduce U.S. gasoline imports over the 2007-2012 period by about 400 TBD from 2005 levels. This change in supply is likely to impact refining economics in the EOR markets and overseas as European companies will likely continue moving surplus blendstocks to the East Coast.

This situation could manifest itself as an advantage to California in two ways. One, Gulf Coast refiners looking to achieve higher margins may opt to produce Arizona grade product and move gasoline from Houston through the Longhorn system into Arizona in the Kinder Morgan East Line. Two, Gulf Coast, or possibly Canadian and Caribbean refiners, could move product to the West Coast on vessels. For movements to California, CARBOB quality capability would be important; however, in an EOR market much shorter of product than current and recent history, some refiners may invest in facilities producing CARBOB to enable them to reach the tighter California market.

Any volume that can move via Longhorn or West Texas/New Mexico refiners into the Kinder Morgan East Line can push volume back into California from the Kinder Morgan West Line. This works to relieve port import requirements and improves supply alternatives into California.

The potential ability of the State of California to influence the movement of product is likely limited. As noted earlier, market conditions do influence movements from PADD 3 to the West Coast and this may be the most appropriate driver.

TASK 2. OVERVIEW OF MAJOR REFINER PROFITABILITY

Introduction and Objectives

In this task, the Energy Commission has requested ICF International (ICFI) to review oil company profitability over the past 10-year period. The request requires broad examination, ranging from a general discussion of profitability measures and the position of the industry within the larger context of manufacturing/industrial profitability, to a detailed examination of specific companies.

At the request of the Energy Commission, ICFI will use data from the U.S. Census Bureau to compare the profitability of the oil industry to that of the manufacturing sector as a whole, and to specific industries which are, and are not, capital intensive. The Energy Commission also has requested an analysis of the profitability of five large integrated oil companies (ExxonMobil, BP, Royal Dutch Shell, ConocoPhillips, and Chevron) and several large domestic refiners, including Valero, over the same time period. Refineries owned by these companies comprise over 80 percent of California's refining capacity.

In addition, the Energy Commission has requested comments on the objectivity of the Ernst & Young study from February 2006 titled "*Investment and Other Uses of Cash Flow by the Oil Industry".* This study, commissioned by the American Petroleum Institute (API) focused on how oil companies re-invested their profits over the time frame of 1992 to 2005 (third quarter).

Collectively, this information should provide an overview of how oil company profitability compares with other industries, how the largest oil companies have performed over the past ten years, and how they have invested their earnings.

Task Request and Methodology

The Energy Commission's Task request (shown below) summarizes the specific areas to be investigated. At the beginning of each subtask section is a summary of the methodological approach and data sources used.

Subtask 2.1: Contractor will prepare a general description of "profitability," examples of various methods to express profits (net income, earnings before taxes, rate of return on capital, price to earnings ratio, percent of revenue, etc.), and recommend a specific method to state refinery profits.

Subtask 2.2: Contractor will analyze:

- *U.S. refining profitability compared to profits earned in comparable industries/businesses, from 1996 to 2004 (on an annual basis), and 2005 to first quarter 2006 on a quarterly basis.*

- *Profitability of other, non-comparable types of businesses (over the same time period) and the limitations involved when comparing refinery profits to profits earned by these other types of businesses.*

Subtask 2.3: Contractor will provide a comparison of U.S. petroleum company profits to international profits over the last 10 years (including the years 1996 through 2004 on an annual basis and 2005 to first quarter of 2006 on a quarterly basis). This comparison will include, but not necessarily be limited to:

- *Upstream Operations (crude oil and natural gas)*
- *Downstream Operations (refining and marketing)*
- *All Remaining Categories*
- *For ExxonMobil, BP, Royal Dutch Shell, ConocoPhillips, Chevron and Valero*

Subtask 2.4: Contractor will prepare a narrative discussing objectivity of the Ernst & Young 2006 study, commissioned by API that discusses oil company use of their earnings. Contractor will describe the credibility of the study, including references to uses of the study by governmental agencies, academic institutions, and others. By use of objective criteria, contractor will demonstrate whether the State of California can rely upon this study to accurately describe how oil companies have used their earnings (if possible, separately state company use of earnings from California operations).

In order to accomplish these tasks, work was coordinated with the Energy Commission and two personnel from the California Board of Equalization (BOE) to assist in review of the data and use of the most appropriate financial measurements.

2.1. Measures of Profitability

The objective of this section is to identify measures of profitability that allow comparison of the profitability of the oil refining sector to other industrial manufacturing sectors. The description will focus first on basic principles of profit and profitability, along with some cautionary observations, and then include commonly used measures that allow comparisons. Implicit in this discussion is finding whether a measure of profits allows one to compare, on a risk adjusted basis, the profitability of the oil industry with other industries while determining if returns to the oil industry are excessive.

Simply stated, profit is the excess of revenues over costs. There are both economic and accounting measures of profit. Economists consider normal profits part of costs; accountants consider profits what is left over after all costs are paid. For this section, ICFI will use the accounting approach since the data are accounting data and the concepts are more easily understood.

The profitability of a company or an industry is a relative measure. It is the ratio of profit to some baseline indicator of the investment and activities that go into generating the profit. Some industries may generate large profits, because of scale for example, but as measured by rates of profit they may appear less impressive. The most common measures of profitability are:

- **Gross profit margin**, the ratio of sales minus the cost of goods sold divided by the total sales. This measure looks at gross profits as a percent of all inputs into the profit generating function.
- **Return on assets** is the ratio of net income (i.e., gross profit less taxes) to total company or industry assets and is a measure of how efficiently assets are being deployed to generate income.
- **Return on equity** is the measure of profit relative to the shareholder equity.
- **Return on capital employed** is a closely related measure of a company's earnings before interest and taxes (EBIT) divided by the difference of its total assets and current liabilities[24].

These ratios are broadly reported for all companies and industries and comparisons between industries are possible and even instructive. Less instructive is the price to earnings (P/E) ratio, which is the ratio of the stock price to the earnings of a company. A high or low ratio indicates how the stock market feels about a company's prospects. P/E ratios are not useful in this analysis.

These accounting concepts raise questions of definition, i.e., what constitutes income, how are taxes treated, and how do we consider depreciation and other notions of revenue that may differ between industries. ICFI will use the standard definitions. It is also difficult to sort out the performance of the sub-sectors of the oil industry because of the dominance of integrated firms. The sub-sectors range from extractive activities to capital intensive industrial processes. There are few firms which operate only in a single sub-sector in to allow straight-forward comparisons of performance.

Profit can be measured over different time periods. The conventional measure is annual, but profits are also reported quarterly. To understand if there are excess profits, one quarter or one year may not be adequate. Also, a snapshot of a profitable or unprofitable company will not be useful in understanding the relative profits of a particular industry. ICFI will report multi-year profits and profit ratios to get a better sense of performance over time.

Accounting measures are normative, and ultimately intended to assay the performance of company management. A spectacular return on assets or return on equity in one year may indicate strong management, but rising tides also lift all ships. High profits can arise from other phenomena, which brings the analyst back to some economic issues. Resource rents happen from time to time. These occur in exploitative industries like oil, fishing, mining, timber, tulips, and so on, where temporary limitations on productive capacity, combined with strong demand can lead to economic rents accruing to the industries in those fields. Whether these are offset by the periods of "subnormal" returns (i.e., when low prices cover average variable costs but no return) is a key issue in the current debate.

Ideally, several measures should be used to measure relative profitability of major corporations. For this study, it is recommended that return on capital employed (ROCE) is the most balanced benchmark to use. This measure is especially useful for capital-intensive industries, such as oil production and refining, because it calculates profitability after factoring in the amount of capital used. ROCE is not comparable across diverse industries, but it still provides a reasonable assessment of different industries' use of capital and management of assets.

ROCE can be evaluated based on earnings in a given period over capital employed in that period, or over average capital employed over a year, three or five year period. For this analysis, ROCE comparisons will be over the current period capital employed to best capture performance trends, impact of mergers, etc.[25]

In evaluating and comparing financial trends of the large oil companies against each other, and in assessing how these corporations managed the large asset changes associated with mergers over the past ten years, ROCE is an excellent tool. In general, analysis of ROCE, or any financial indices, should be considered over an appropriate period of time This is particularly true when evaluating an industry that can take many years to build the massive capital projects required to explore, produce, and refine hydrocarbons. We believe that 10 years is a minimum for the oil industry. We also recommend that future consideration be given to factors that affect underlying resource scarcity, such as relative commodity indices.

2.2. Comparison of the Oil Industry to Other Manufacturing Sectors

2.2.1. Background and Data Availability

The profitability of the petroleum refining industry in the U.S. was analyzed and compared to several other capital-intensive industries and non-capital intensive industries. The goal was to determine the profitability, as measured by profit margin and ROCE, of the petroleum industry versus other U.S. manufacturing industries.

In order to analyze such a broad number of manufacturing industries, U.S. Census Bureau data were used. The Census Bureau data comes from the *Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations*, which is based on an extensive sample survey and reports on financial statements (10-K reports) of the domestic operations for corporations with assets over $250,000. The "Petroleum and Coal Products Manufacturing" category is NAICS[26] code 324. Its definition stipulates: "The Petroleum and Coal Products Manufacturing sub-sector is based on the transformation of crude petroleum and coal into usable products. The dominant process is petroleum refining that involves the separation of crude petroleum into component products through such techniques as cracking and distillation. In addition, this sub-sector includes establishments that primarily further process refined petroleum and coal products and produce products, such as asphalt coatings and petroleum lubricating oils."

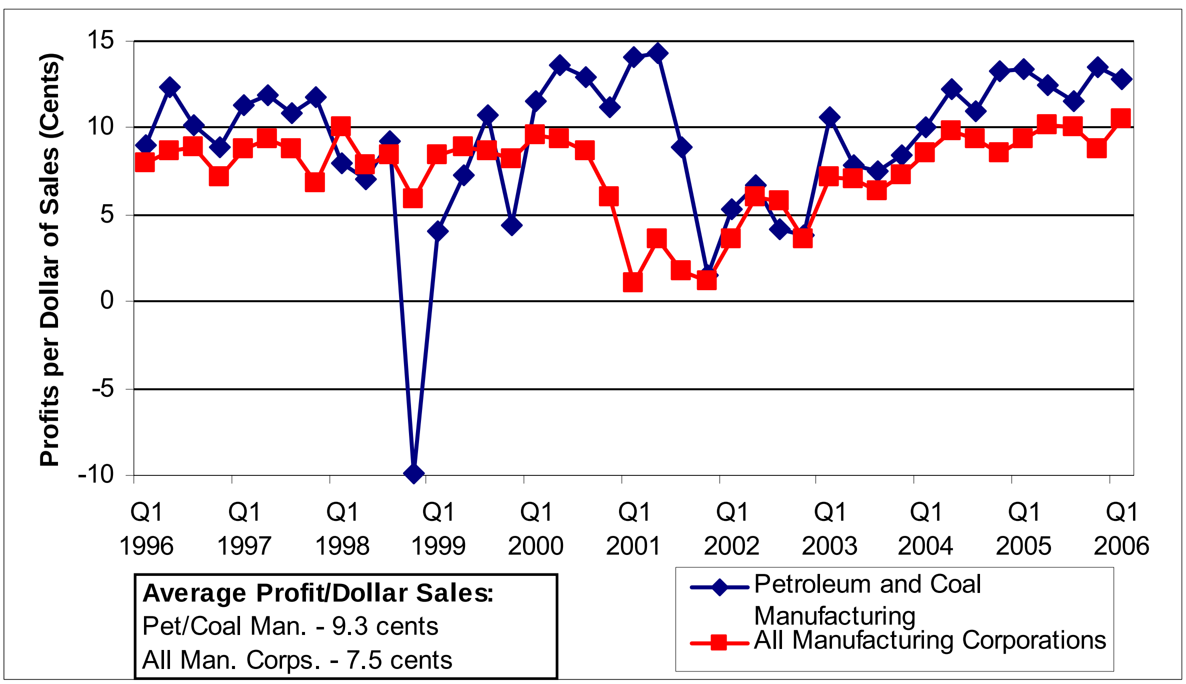
While this definition is clearly not as narrow as the intended concentration of petroleum refining, Energy Information Administration (EIA) data on coal and petroleum consumption demonstrates that NAICS code 324 is an apt proxy for petroleum refining. In 2005, U.S. coal consumption was about 1.13 billion short tons with an average coal spot price fluctuating between $20 and $40 per ton; therefore, coal sales amounted to between $22.6 and $45.2 billion. The Census Bureau data show that sales in the Petroleum and Coal Products Manufacturing category during the same year were just under $1 trillion. Consequently, the coal products manufacturing sector accounts for, at most, 5 percent of the total category. Thus, it is reasonable to assume that the petroleum portion of the category is around 90 percent, taking into account other manufacturing processes in NAICS code 324 that are irrelevant to this study (i.e., asphalt coatings).

For comparing oil industry profits to other manufacturing industries, ICFI used quarterly data from the U.S. Census Bureau on the profit level of U.S. petroleum and coal companies from 1996 to the most current quarter and compared it to "all manufacturing." In addition, ICFI tracked the "Petroleum and Coal" sector versus other key capital intensive industries (metals, paper, and chemicals) and separately compared it to profits earned by non-comparable businesses (food and beverage, apparel and leather, and transportation equipment) over the same time period. This information was evaluated on a “profit per dollar of sale” basis for petroleum and coal versus all manufacturing. In addition, the financial information was compiled on a return on capital employed basis (ROCE) for comparison with other specific manufacturing industries as noted above.

2.2.2. Results

In general, the Petroleum and Coal Manufacturing industry has mirrored the trends of all manufacturing corporations over the past decade, albeit with a greater degree of volatility. Exhibit 67 shows that the Petroleum and Coal Products Manufacturing industry has earned an average of 1.8 cents per dollar of sales more than all manufacturing corporations in the past decade, but it has also endured more pronounced volatility in its profitability than manufacturing industries as a whole. The evaluation of earnings as a percentage of sales revenue, or profit margin, is one economic measure; however, it does not provide a comprehensive perspective on how a corporation is managing its overall capital employed.

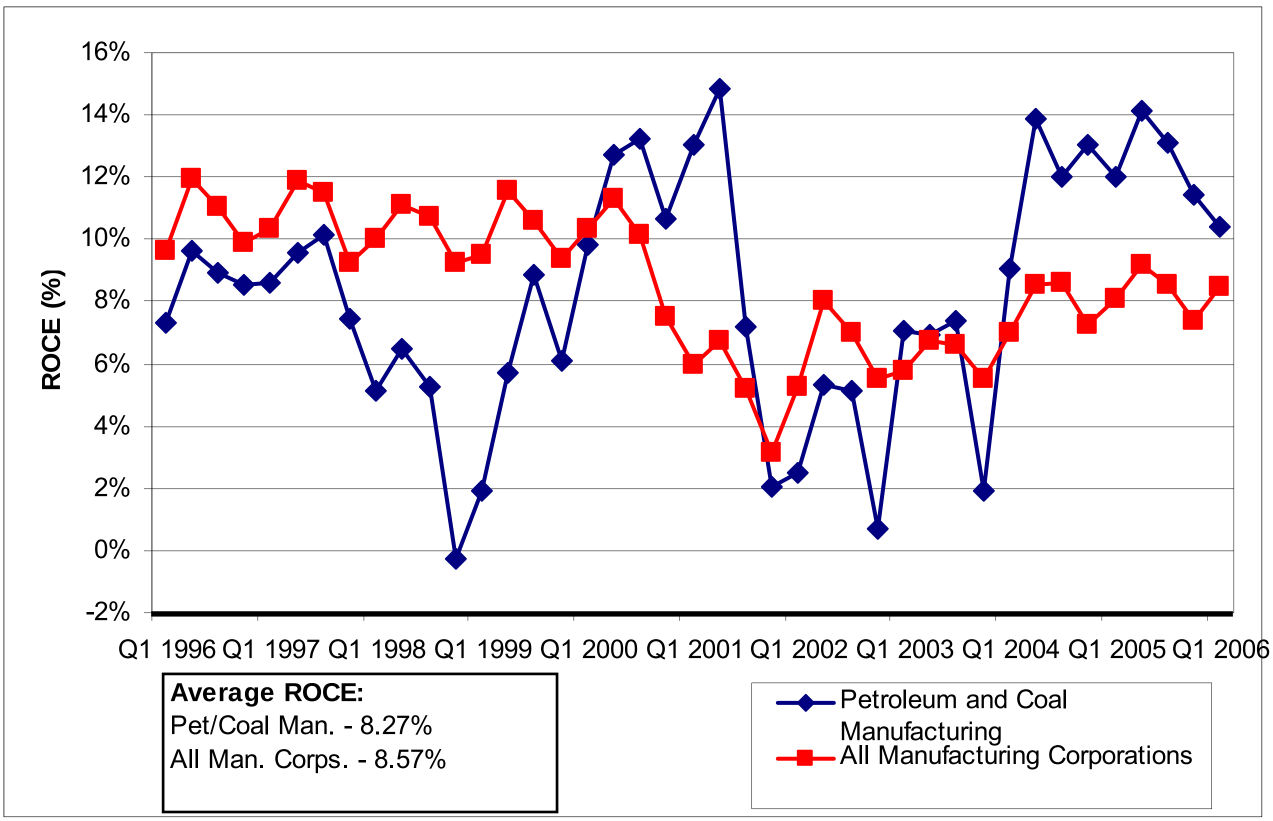
Exhibit 67. Profitability Before Income Taxes of Petroleum/Coal vs. All Manufacturing



Source: U.S. Census Bureau - *Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations*

ROCE (Return on Capital Employed) is a better metric for how a company or industry is managing business since it better accounts for all the activities involved in managing a business and utilizing capital. Exhibit 68 shows the ROCE for Petroleum and Coal manufacturers versus all of manufacturing. Petroleum and Coal Manufacturing is more volatile and more affected by international business and political developments than the average manufacturing corporation. For example, the 1997-1998 Asian financial crises, had a markedly greater impact on the petroleum industry, since it halted the strong growth in petroleum demand in Asian nations (prior to 1997) and caused oil prices to drop substantially. Exhibit 68 shows a steady decline in ROCE, culminating in negative returns for the fourth quarter of 1998. This impacted the oil industry globally, as the outright price of oil fell substantially, and the recession lowered demands and refining margins.

Exhibit 68. Return on Capital Employed: Petroleum/Coal Manufacturing vs. All Manufacturing Corporations



Source: U.S. Census Bureau - *Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations*

In contrast, the recession sparked by the terrorist attacks of September 11, 2001, had an adverse effect on all U.S. manufacturing corporations, including petroleum.

Financial measures, such as ROCE, of the U.S. Petroleum and Coal Manufacturing industry have been higher the first quarter of 2004 until the first quarter of 2006 compared to their average over the previous decade. The ROCE of over 12 percent in these two years can be attributed to strong global demand growth for petroleum—spurred mostly by China's phenomenal economic expansion—which fueled higher demand for crude oil and tightened global crude spare capacity, driving prices up. At the same time, refining capacity was stretched worldwide to meet the product demand growth, increasing refinery margins. In a sense, there was a “bidding war” for products to meet global demands.

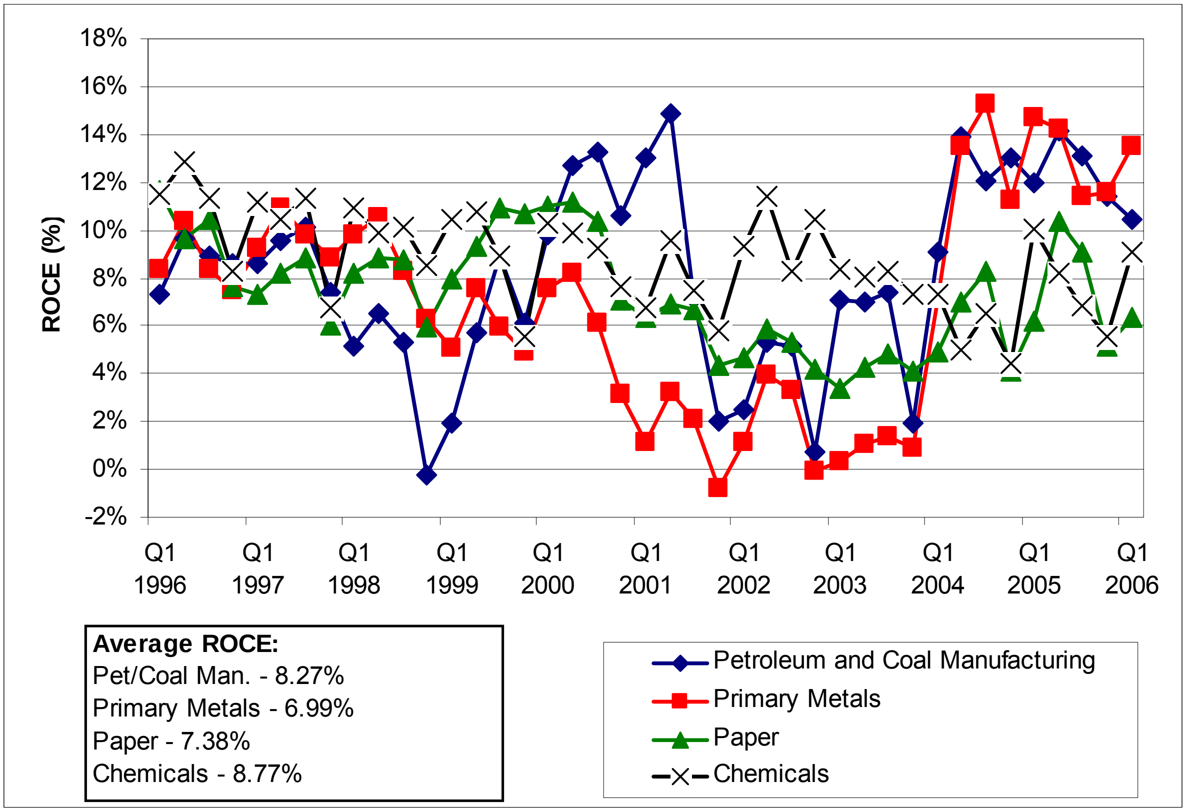
The overall U.S. manufacturing sector has yet to fully recover from the effects of September 11, 2001, as evidenced by an average ROCE of 9.8 percent prior to 9/11 compared to an average ROCE of 7 percent after 9/11. The gap between financial returns for the U.S. Petroleum and Coal Manufacturing industry versus all of manufacturing may remain in the short to medium term. Demand for petroleum products has proven to be relatively inelastic in the face of high oil prices, in addition to the globalization effects of outsourcing more and more manufacturing jobs to more labor-abundant nations.

The peaks and troughs for U.S. Petroleum and Coal Manufacturing are much more pronounced than those for all of manufacturing. This effect occurs because petroleum commodity markets are very volatile and the petroleum industry overall is a capital-intensive enterprise. In fact, according to U.S. Census Bureau data, $44,729 per worker has been spent on machinery and equipment in petroleum and coal manufacturing as opposed to $7,321 per worker for all manufacturing corporations over the past decade.

2.2.3. A Comparison with Other Capital-Intensive Industries

ROCE is an especially good financial indicator for capital-intensive industries, which, by definition, require a lot of invested capital in order to produce their goods. When comparing Petroleum and Coal Manufacturing to other capital-intensive industries (paper, primary metals, and chemicals) the overall picture of market forces governing these industries’ financial returns is consistent. The average ROCE for all four of these industries over the past decade lies between roughly seven and nine percent (See Exhibit 69). The same type of demand and supply factors can be used to explain the noticeable rises and falls in ROCE for these capital-intensive industries. China’s incredible economic expansion, for example, is certainly one of the main drivers for the startling increase in ROCE in the primary metals industry. Overall, Petroleum and Coal Manufacturing has earned an average ROCE of 8.27 percent over the past decade, which lies within the range of 6.99 to 8.77 percent for the capital-intensive industries in the analysis. Furthermore, the returns for Petroleum and Coal Manufacturing since 2004 (12.12 percent) are on par with that of the Primary Metals industry (12.5 percent).

Exhibit 69 Return on Capital Employed: Capital-Intensive Industries



Source: U.S. Census Bureau - *Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations*

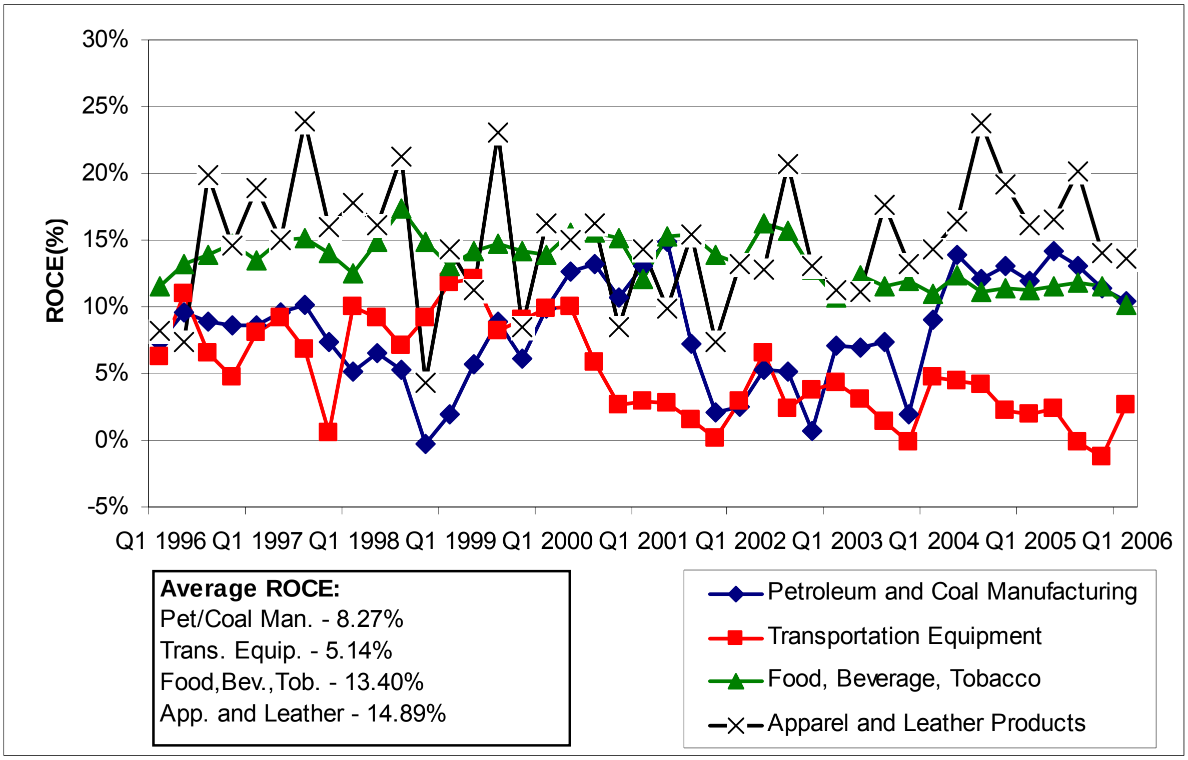
2.2.4. A Comparison with Non-Capital Intensive Industries

Financial comparisons across different industries can involve certain factors which may not always result in a completely balanced comparison. Comparing the ROCE for a capital-intensive industry such as Petroleum and Coal Manufacturing versus industries with lower capital intensity levels, for example, may not be ideal. However, using ROCE can still demonstrate the relative profitability of the Petroleum and Coal industry to non-capital intensive companies.

Based on the analysis of Petroleum and Coal Manufacturing with several non-capital intensive business segments (See Exhibit 70), several observations can be made. Based on the Census Bureau data, net income in Petroleum and Coal Manufacturing is around four times higher than that of Apparel and Leather Products. However, the Apparel and Leather industry has an average ROCE over 6.5 percent greater than Petroleum and Coal Manufacturing in the past decade. Average ROCE is higher than Petroleum and Coal Manufacturing (8.27 percent) for Food, Beverage, and Tobacco (13.4 percent) and Apparel and Leather Products

(14.89 percent) partly because the latter two sectors do not have to make large, periodic capital investments to produce their goods.

Exhibit 70 Return on Capital Employed: Petroleum/Coal Manufacturing vs. Non-Capital Intensive Industries



Source: U.S. Census Bureau - *Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations*

The Apparel and Leather industry has volatility in ROCE, but it appears to be heavily seasonal in nature, as may be expected. The inelastic Food, Beverage, and Tobacco sector, on the other hand, experiences very little volatility in ROCE, and has sustained good performance based on the Census Bureau figures. The Petroleum and Coal Manufacturing group, and the Transportation Equipment group, each have their own operational business cycles of high and low levels of ROCE, but with weaker performance.

The comparison of diverse segments as in this analysis can be difficult to sort out because of the vastly different nature of the segments. Financial measures other than ROCE may have similar anomalies if used for comparison. In general, the analysis of Petroleum and Coal Manufacturing versus non-capital intensive industries, with a uniform measurement (ROCE), shows that Petroleum and Coal Manufacturing (8.27 percent ROCE) performed within the bounds of the non-capital intensive sectors (5.14 to 14.89 percent).

This analysis could be extended to more sectors in the non-capital intensive area to increase the “sample size”; however, it would likely not provide any substantially better conclusions.

2.3. Major Oil Company Profit Analysis

For the evaluation of the profits of the six major oil companies, the Energy Commission utilized access to the John S. Herold Financial Database. The Herold database contains extensive information pulled from public corporations' 10-K and other financial reports.

The work done in the company analysis utilized the Herold database as well as insights and analysis of refinery capacity and market activity over the study period. ICF, the Energy Commission, and the BOE accounting resources concurred that evaluation of Earnings Before Interest, Income Taxes, Depreciation, and Amortization (EBITDA), and ROCE were key tracking measures.

2.3.1. Overview

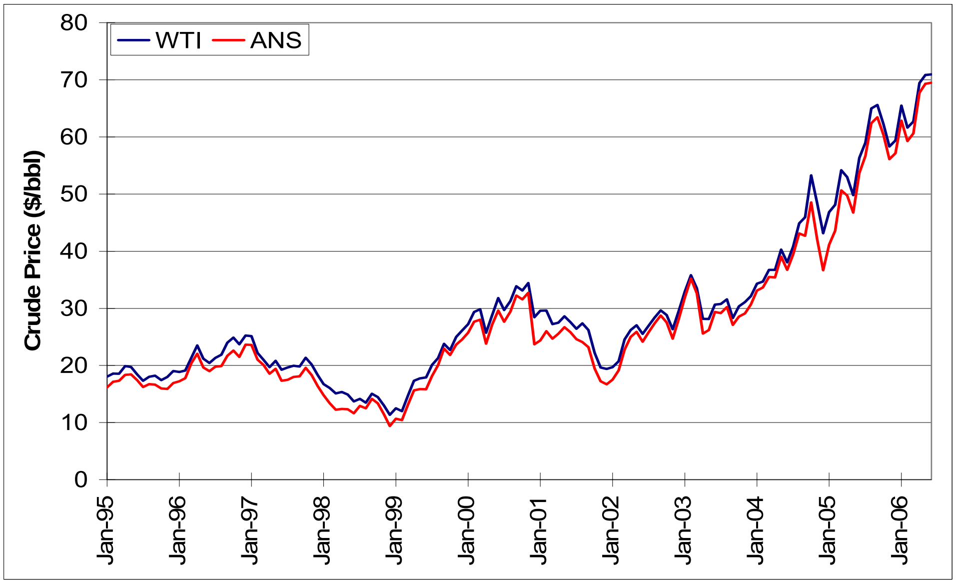
Over the past ten years there have been major changes in the structure of the global oil industry. There has been significant growth in both influence and power of National Oil Companies (NOCs) such as Saudi Aramco, Nigerian National Oil Company (NNPC), Venezuela, Mexico and Brazil (PDVSA, Pemex and Petrobras) along with the major companies in India and China.

The traditional core of technical and project management expertise remains with the International Oil Companies (IOCs) as well as the mega-construction companies like KBR, Bechtel, Fluor and others who have the expertise to manage the NOC and IOC capital spending plans.

For the Integrated [27]International Oil Companies, the past decade has seen some significant changes in their business. Natural gas, through increased global demand, and increasing global commoditization through the LNG business, has become a more capital intensive industry, with a higher valued product, and significant growth potential. The oil production and refining business has experienced the lows of the Asian recession in 1998-1999 and the overall recession following the events of 9/11/2001. It has also enjoyed a significantly better financial performance from 2003 onwards as global economies have surged, leading to increasing oil demand and constraining both oil production capacity and refining capacity.

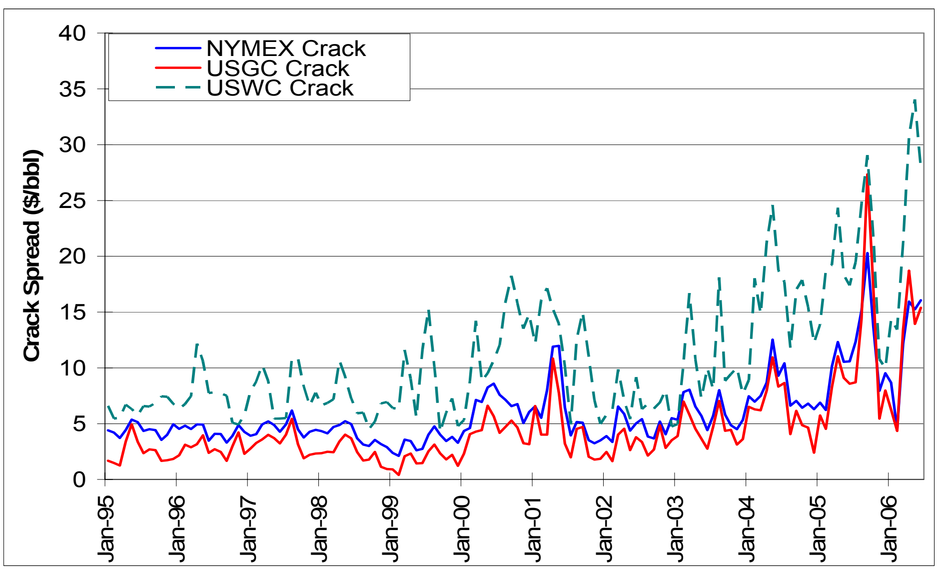
In the 1995-2002 timeframe, crude oil prices languished at levels of $15 to $20 per barrel for West Texas Intermediate (WTI) crude, rising to the $30 level in 2000, but then declining again in the 2002 recession period (See Exhibit 71). Refinery margins, as measured by the "crack spread"[28] between gasoline and distillate and crude oil, also were very weak over the same period (See Exhibit 72). These refining margins were significantly weak prior to 2000, increased in the 2000/2001 period, and then declined in 2002 again.

Exhibit 71. Historical Crude Price, $ per barrel



Source: EIA - Petroleum Navigator

Exhibit 72. Historical Crack Spread, $ per barrel



Source: EIA – Petroleum Navigator

During this period of low prices and weak margins many oil companies sought ways to improve their performance. At the same time, refineries in particular were faced with new environmental specifications for fuels that required capital investment and/or operational changes. The weak refining margins coupled with required capital for stay-in-business refining projects led to some of the additional refinery closures identified in Task 1 in both the U.S. overall and in California. Overall refinery capacity continued to grow because of smaller scale investments at each location.

More significantly, oil companies explored options to lower their cost structure and expenses. Project investments at refineries became focused more on reliability, energy conservation, and reducing crude costs by improving crude flexibility and yields. This period stimulated the wave of mega-mergers and acquisitions that transformed the historical makeup of the oil industry in the U.S. and worldwide.

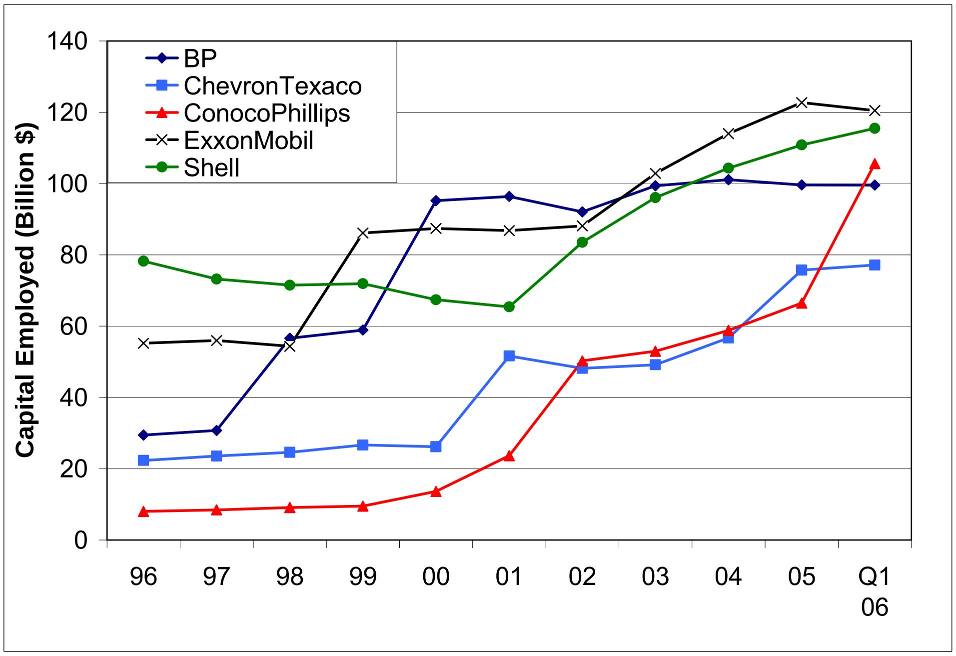
The notable mergers were:

- Exxon's acquisition of Mobil in 1999;
- BP's acquisition of Amoco and subsequently Arco in the same timeframe;
- Chevron's acquisition of Texaco;
- Conoco's acquisition of Tosco, followed by Phillips and Conoco's merger; Valero's acquisition of several refineries from other majors, Ultramar Diamond Shamrock and, more recently, from Premcor.

While the particular strategies and logic driving these decisions may have been different fundamentally, each company had determined that the mergers were integral to the companies' long-term success with shareholders. Mobil's strong presence in natural gas and in African crude production was a good complement to Exxon. BP's acquisition of both Amoco and Arco represented a significant step up in overall size to allow them to compete on a global playing field. After looking at a bigger ExxonMobil, bigger BP, and an already large Royal Dutch Shell, Chevron was faced with a decision to either become bigger to compete with better economies of scale, or consider selling out to one of the larger companies. Chevron and Texaco's merger was, in part, a defensive strategy. ConocoPhillips followed a somewhat similar path to Chevron, but with multiple steps along the way. Conoco bought Tosco, who had just acquired Mobil's significant Northeast U.S. marketing assets as part of an FTC-required divestment from the Exxon merger. Phillips then merged with Conoco to form ConocoPhillips. Valero, a small U.S. independent refiner early in this time period, saw an emerging value in refinery assets, and began a strategy to "buy" existing refineries from other companies, upgrade them, and streamline the operation. Valero has executed this strategy to the point that they are now the largest refining company in the United States.

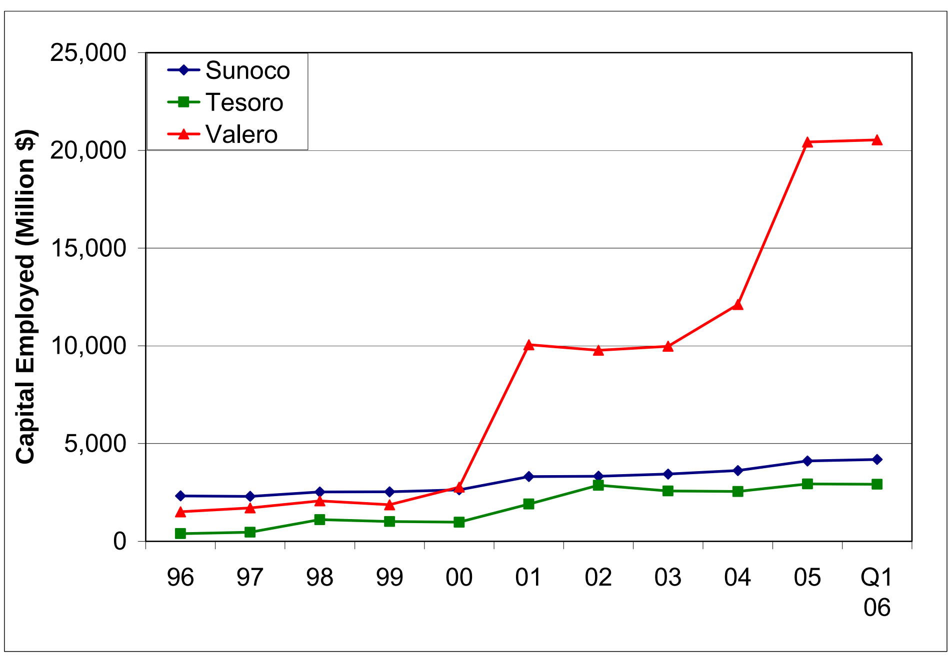
Exhibit 73 and Exhibit 74 show the overall growth in capital employed by these companies over the period. For comparative purposes, the first exhibit shows the integrated majors and second one shows large U.S.-based refiners.

Exhibit 73. Trends in Capital Employed for Major Integrated Oil Companies, 1995-2005, $ Million



Source: John S. Herold, Inc. – Herold Financial and Operations Database

Exhibit 74. Trends in Capital Employed for U.S. Refiners, 1995-2005, $ Million



Source: John S. Herold, Inc. – Herold Financial and Operations Database

Both the exhibits show the impact of some of the major acquisitions over the period, along with sustained overall growth in capital employed for each company. The extent of the changes in ownership and consolidation of business were significant; however, the operational integration of the merged companies' physical assets was relatively smooth.

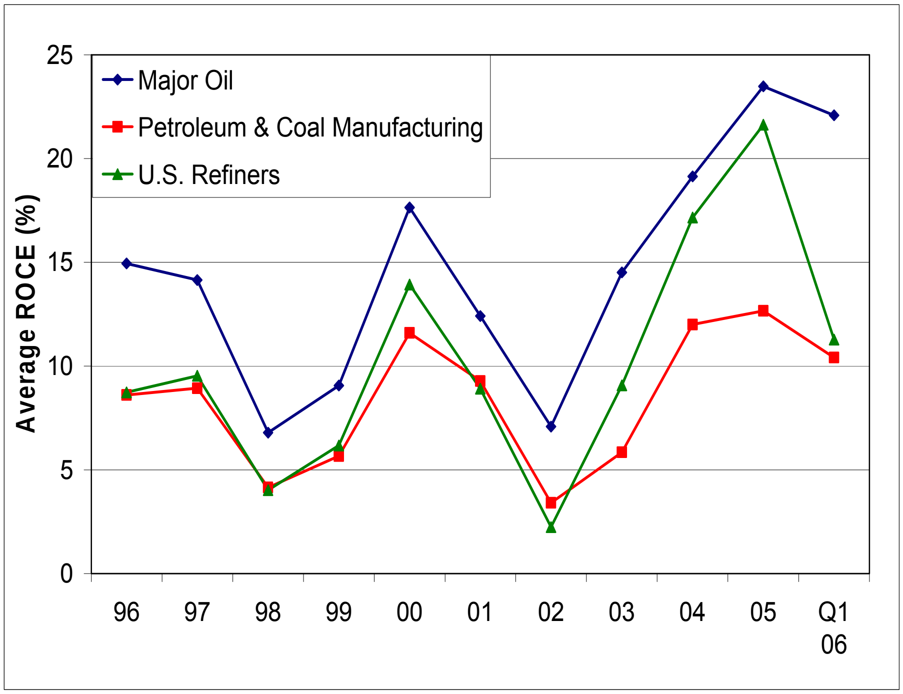
The financial effect of the mergers, of course, appeared in the companies' financial ratios. For this comparison, the ROCE (return on capital employed) is an appropriate benchmark. The ROCE incorporates all the significant factors that a major oil company deals with in managing the business. The sheer financial size of the assets, operational actions to reduce working capital and optimize performance, actions to divest weak or underperforming assets, marketing and pricing strategies, etc. are all incorporated in the ROCE determination. The ROCE will also allow larger competitors to be evaluated on the same "playing field" by focusing the analysis on the profit per dollar of capital employed; that is, the "scale" benefit tends to be diminished.

2.3.2. Comparison of Results with U.S. Census Bureau Data

Initially, the ROCE for the five integrated majors and three U.S. Refiners were compared with the "Petroleum and Coal Manufacturer's" ROCE as reported in Task 2.2. The ROCE data for the companies was developed from the John S Herold database, which provides detailed information on oil and gas industry financial data over an extended period of time. The Herold data on ROCE is for the worldwide operation of the companies; hence, for the *integrated majors* it incorporates all non-U.S. income and assets as well as domestic. For the large U.S. *refiners*, the Herold data should represent U.S. ROCE.

As noted in Task 2.2, the Census Bureau data is developed from U.S. operations of Petroleum and Coal industry companies[29]. Exhibit 75 shows this comparison.

Exhibit 75. ROCE for Major Oil Companies vs. U.S. Census Bureau Based ROCE for “Petroleum and Coal Manufacturers”



Source: John S. Herold, Inc. – Herold Financial and Operations Database

This chart shows a strong relationship between the Census Bureau data and the average ROCE reported by the companies through 2002, with the international majors showing stronger performance than domestic refiners because of their more diverse portfolio and the profitability of foreign assets. Results began to diverge in 2003 as crude prices, natural gas prices, and crack spreads achieved higher levels, increasing the earnings of both the international majors and, to a lesser degree, U.S. Refiners (See Exhibit 76).

Exhibit 76. Crude, Gas, and Refining Margin Marker Prices[30], 1995-2006

Year	3-2-1 Crack Spread ($/bbl)			Crude Spot Prices ($/bbl)		Henry Hub ($/MMbtu)
	USGC Maya	USGC WTI	USWC ANS	WTI	ANS	
1995		2.42	6.50	18.44	16.93	1.70
1996		2.84	7.49	22.11	20.44	2.51
1997	8.95	3.30	8.05	20.61	18.98	2.47
1998	8.11	2.41	6.92	14.45	12.55	2.16
1999	6.75	1.82	8.18	19.26	17.73	2.31
2000	11.86	4.38	12.30	30.30	28.28	4.31
2001	13.12	4.44	11.70	25.95	23.21	4.03
2002	8.51	3.21	6.89	26.11	24.72	3.36
2003	11.49	4.58	10.20	31.12	29.64	5.50
2004	17.96	6.42	16.52	41.44	38.84	6.19
2005	26.48	10.69	18.97	56.49	53.48	9.00
Q1 2006	23.93	8.13	16.42	63.32	60.96	7.89

Source: EIA – Petroleum Navigator

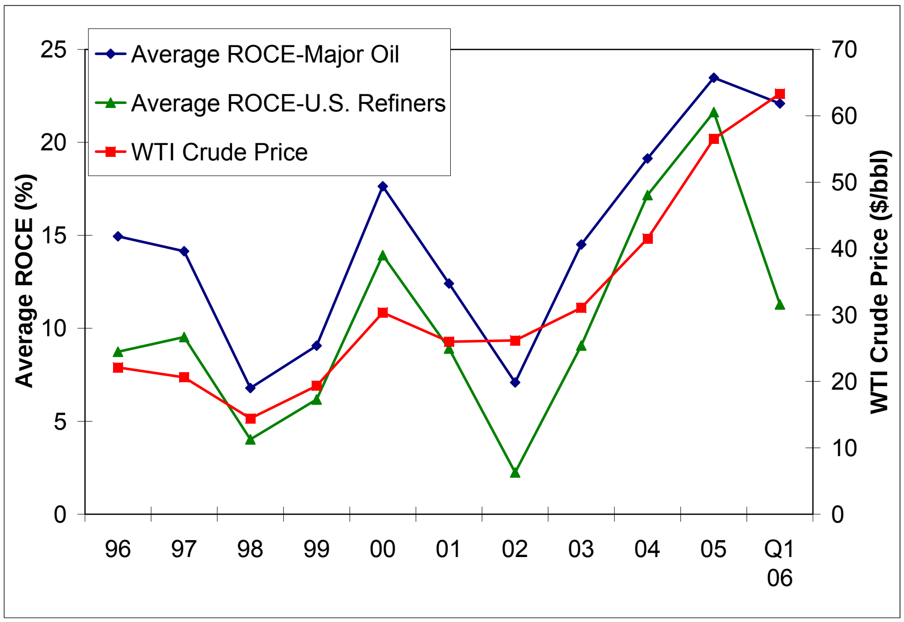
In 2004 and 2005, the crack spreads more than doubled from 2003 levels, and crude and natural gas prices increased substantially as well. These changes in market pricing significantly increased ROCE for the international majors and even more so for the U.S. refiners (since the rise in refining margin was more pronounced than the crude and gas price increase). The worldwide increases in crude price and margins, coupled with the refining sector improvement, elevated the 2005 overall ROCE performance of the international majors well above the ROCE of the "Petroleum and Coal" category of the U.S. Census Bureau segment (which is domestic only).

2.3.3. Comparison of Results within the Refining Group

In the first quarter of 2006, performance of U.S. refiners declined for several reasons. First, the crack spread declined from the post-hurricane levels in the fall of 2005 as the U.S. overall supply system continued to recover. Secondly, refiners typically perform maintenance in the first quarter, which reduces throughput and revenue. This year, there was extensive maintenance as many refiners not affected by the hurricanes postponed planned fall work to sustain supply of product during the emergency. The refining industry typically needs to reduce refinery crude runs in the first quarter by 5-8 percent from higher summer utilization rates. These activities led to a significant impact on domestic refiners, but less so on the returns of the integrated majors (whose ROCE includes significant foreign earnings).

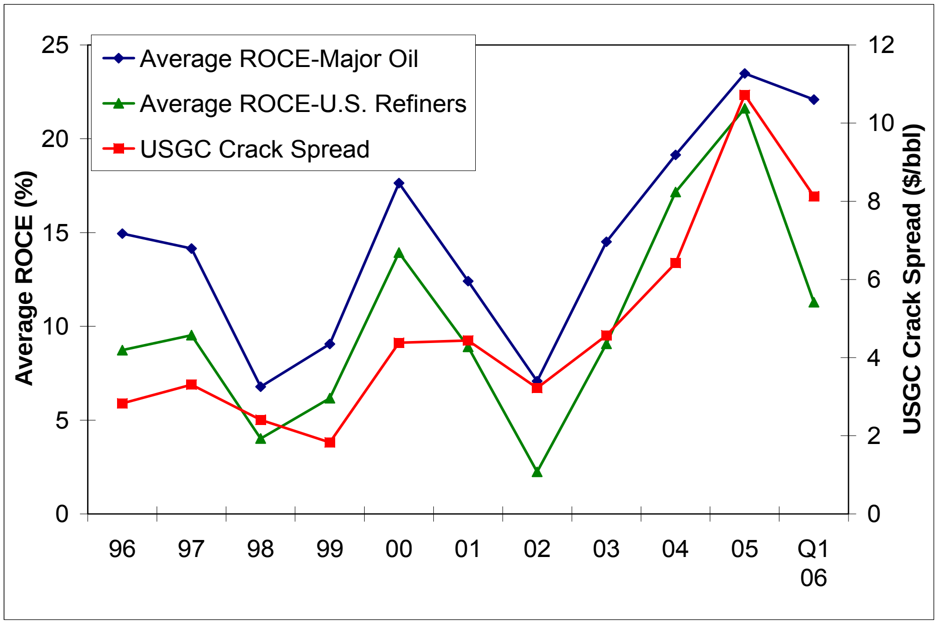
Exhibit 77 shows the ROCE for the major integrated oil companies and Exhibit 78 the U.S. refiners over the period tracked against the WTI crude price and the U.S. Gulf Coast (USGC) crack spread. These graphics show that the ROCE for the companies follows these two key indicators very closely. As noted earlier, the integrated majors include extensive foreign investments as well as domestic, and hence, the ROCE is influenced by crude price, crack spread, and also natural gas and chemical markets. As producers, the integrated companies make money as absolute crude and natural gas prices rise; as refiners, they make money as product prices rise relative to crude price (as evidenced in a wider crack spread).

Exhibit 77. Average ROCE and Crude Price: Major Oil vs. U.S. Refiners



Source: John S. Herold, Inc. – Herold Financial and Operations Database

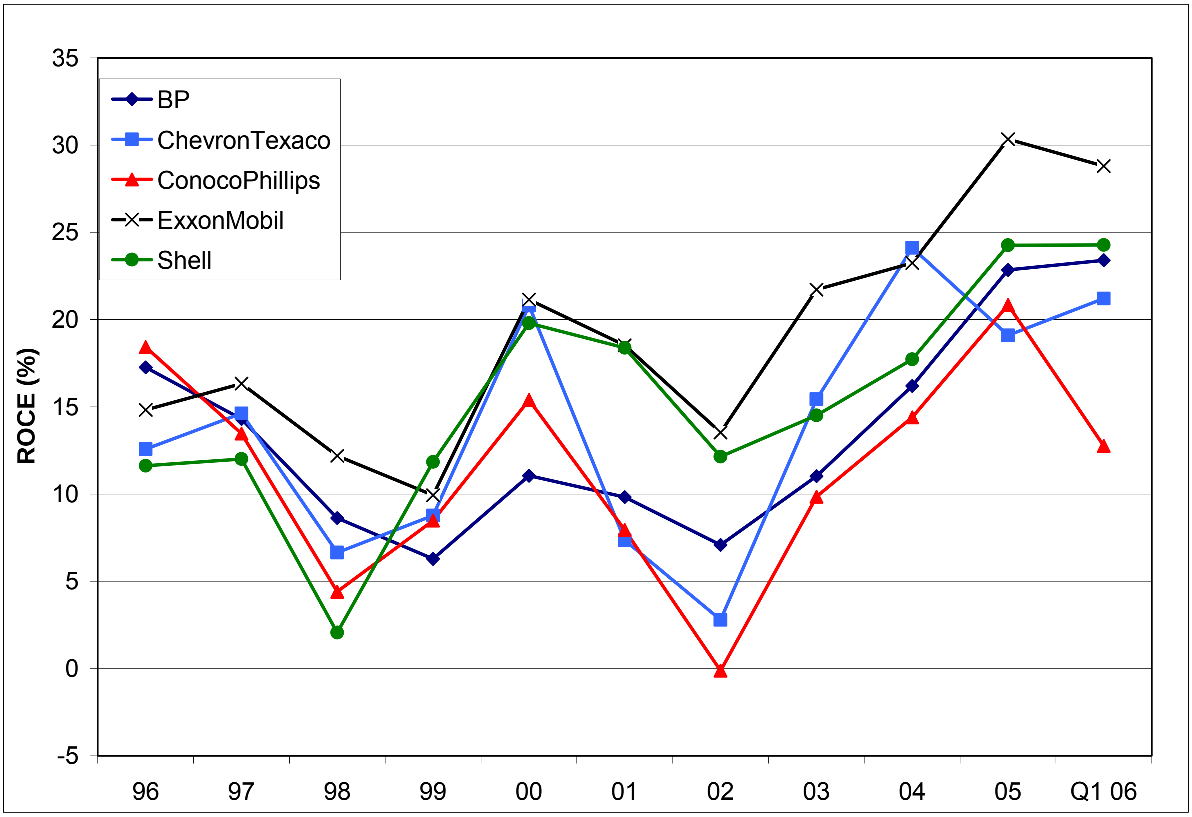
Exhibit 78. Average ROCE and Crack Spread: Major Oil vs. U.S. Refiners



Source: John S. Herold, Inc. – Herold Financial and Operations Database

The U.S. refiners are essentially buyers of crude oil and sellers of products; hence, the absolute crude price is not as relevant to these companies. The U.S. refiner exhibit shows a significant sensitivity to changes in crack spreads over time. Individual companies' performance is also highly dependent upon the refiners' ability to efficiently process crude, optimize crude purchase strategy, and fully utilize the refinery capability. Exhibit 79 shows a comparison of the five integrated majors' performance over the period. These results are for the parent company (for example, the ExxonMobil chart represents Exxon performance prior to 1999, with Mobil included after the merger). These data show an industry that has strong and weak periods, and has companies who outperform and lag others in their peer group.

Exhibit 79. Return on Capital Employed for Major Oil Companies



Source: John S. Herold, Inc. – Herold Financial and Operations Database

In summary, the oil industry profitability, as seen in both the Census Bureau data as well as an examination of specific corporate entities, is highly dependent upon commodity values and supply and demand factors. The recessions in 1998 and 2002 clearly influenced absolute prices of commodities as well as refining margins. Lower global demands resulted in lower commodity prices for consumers and lowered profits for the oil companies.

2.3.4. Overall Profitability Conclusions

The primary “lessons learned” from this analysis are:

1. Periods of global recession and global expansion significantly influence oil industry profitability. High demand growth periods such as 2004 and 2005 put upward pressure on crude prices and product margins, as both crude production capacity and refinery capacity were tight worldwide.
2. Periods of recession depress product demands and soften margins and pricing, thereby negatively impacting ROCE and other financial performance measures.

3. Product price volatility is the greatest in times and regions when product supply is very tight, as evidenced from crack spread histories.
4. Oil companies tend to have greater volatility in earnings than other manufacturers, both capital intensive and non-capital intensive, but in general, the relative ROCE performance of the different industry groups was not materially different.
5. The trend of ROCE over the study period for the integrated major oil companies indicates that each of the largest companies (ExxonMobil, BP, Shell, Chevron and ConocoPhillips) experience almost identical hills and valleys in the ROCE performance that mirror market changes. Nonetheless, the spread of performance between the “highest” and “lowest” ROCE in any given period for this grouping indicates that there can be variability in results of 5-10 percent ROCE between the best and poorest performing company.

2.4. Comments on the Ernst & Young Report on Investment and Other Uses of Cash Flow by the Oil Industry

The petroleum industry is a technology dependent industry and as such is highly capital intensive. Substantial amounts of capital are expended each year to meet the challenges of producing hydrocarbons in increasingly difficult environments or on new refining technologies that are driven by the tightening requirements of product specifications and environmental controls.

The U.S. international oil companies (IOC's, the large vertically integrated companies) are faced with increasing restrictions on where they can operate in the world. These restrictions can vary from an outright ban on there participation in developing a countries resources to limited participation. There are also more amorphous forms of control such as punitive taxes, lack of control over business decisions, and the cost of dealing with countries that do not have clear and transparent business laws. Consequently the IOCs are operating in more extreme environments such as the Arctic and the deep ocean. These areas demand cutting edge technologies and are often environmentally sensitive. The out shot of this is high costs. BP's North Star development in the waters off the Alaskan North Slope, for example, is estimated to have cost over $1 billion for a relatively low annual production rate.

Oil company developments are not short term. Factoring in permitting, environmental considerations, and possible local opposition developments can take 4 to 5 years or even longer if transportation infrastructure also has to be developed. If exploration activity is included any given development can take a decade or more. Consequently, investment decisions are long-term. Even refinery investment driven by regulation can take anywhere from 18 months to 4 years.

Given all of this oil companies tend to be conservative in their investment decisions. Leaving aside investments required by government regulations the major determinant of investment is the long-term price of oil which will drive future earnings and profits. Oil companies do not make their decisions based on a short-term spike in oil prices. They also keep in mind the fact that there historically has been a boom and bust history in oil prices. This is reflected in the fact that most companies were slow to raise their long-term oil price forecast.

There has been considerable discussion in the newspapers over the last few years about how and on what oil companies are spending capital. Profits are perceived as high and there has been extensive coverage on buy back of shares and the pay down of debt. There has also been some discussion as to whether or not oil companies are making appropriate investments.

The American Petroleum Institute (API) retained Ernst & Young to examine the expenditures of the oil industry and delineate the pattern of investment made from cash flow over the last decade. The report, *Investment and Other Uses of Cash Flow by the Oil Industry*[31], was published on February 3, 2006. The report examines in detail uses of cash flow by the industry. Data is provided on the types of expenditures both in absolute dollar amounts and in percentage distributions. The analysis is based on publicly available data: largely the John S. Herold, Inc. database and the Energy Information Administration's Financial Reporting System. Overall views on global investment requirements were drawn from the International Energy Agency's World Energy Investment Outlook 2003. Short term investment activities were taken from surveys conducted by Citigroup and Lehman Brothers.

At the request of the Energy Commission ICFI conducted a search to determine whether or not the Ernst & Young report has been cited in any studies or speeches by the private and the public sector. ICFI also contacted API as the organization does keep track of uses of its' reports. Both our independent search and the API search failed to turn up any cites. The conclusion is that the report is too new for it to have been used in studies, speeches, and analysis.

Nevertheless, ICFI has concluded that the report can be used by the Energy Commission and relied on. The data sources are reputable and the data reflect trends that have been widely discussed and agreed upon by a multitude of sources. For example, the estimated decline in investment that is shown for 2004 is likely a reflection of the bottlenecks and constraints that have emerged in the support industries (engineering and construction industries, rig builders, etc.).

The report appears to be a straightforward application of the public financial data into a cogent analysis of the industry's use of capital.

GLOSSARY

Alaska North Slope (ANS) Crude: Petroleum extracted from the northern slope of the Brooks Range along the coast of the Arctic Ocean in Alaska. The petroleum is transferred south by the Trans-Alaska Pipeline System to Valdez on the Pacific Ocean.

Alkylation: A refining process for chemically combining isobutane with olefin hydrocarbons (e.g., propylene, butylene) through the control of temperature and pressure in the presence of an acid catalyst, usually sulfuric acid or hydrofluoric acid. The product, alkylate, an isoparaffin, has high octane value and is blended with motor and aviation gasoline to improve the antiknock value of the fuel.

API Gravity: Measure of specific gravity of crude oil or condensate in degrees. An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of degrees API; it is calculated as follows: Degrees API = (141.5 / sp.gr.60 deg.F/60 deg.F) - 131.5

Biofuel: Liquid fuels and blending components produced from biomass (plant) feedstocks, used primarily for transportation.

CAFE Standards: Corporate Average Fuel Economy. Program initiated in 1975 as part of the Energy Policy and Conservation Act. The near-term goal was to double new car fuel economy by model year 1985.

Capacity Creep: Additional capacity at a refinery from marginal investments or operational changes that increase throughput.

CARBOB: An acronym for California Reformulated Gasoline Blendstocks for Oxygenate Blending. This is unfinished motor gasoline that meets the requirements of the CA RBOB regulations promulgated by the California Air Resources Board. This base gasoline is designed to be blended with an oxygenate (ethanol) in order to comply with California's finished reformulated gasoline regulations.

Coking Capacity: Refining process used to produce naphtha, distillates, and petroleum coke from the heavier products of vacuum distillation.

Complexity: A measure of the degree of refining processes used within a refinery to convert crude oil into a range of products.

Crack Spread: Crack Spread is a measure of the value of the refinery products minus the cost of the crude, or the gross margin. In the United States, the typical full upgrading refinery produces fuel products in a ratio of about 2 barrels of gasoline and one barrel of jet/distillate per barrel our of every 3 barrels of crude. Although not exact, the crack spread “yardstick” takes the sum of 2x gasoline spot price plus 1x distillate spot price and subtracts 3x crude price to give a general margin indicator of refinery gross margin (known as a 3-2-1 crack spread)

Downstream: The selling and distribution of products derived from crude oil. The downstream industry includes oil refineries, petrochemical plants, petroleum products distributors, retail outlets and natural gas distribution companies.

Energy Information Administration (EIA): An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and analyzes and models energy issues. The Administration must meet the requests of Congress, other elements within the Department of Energy, Federal Energy Regulatory Commission, the Executive Branch, its own independent needs, and assist the general public, or other interest groups, without taking a policy position.

Energy Policy Act of 2005: A public law passed by the U.S. Congress in the summer of 2005. The Act increases the amount of biofuel (usually ethanol) that must be mixed with gasoline to triple the current requirement (7.5 billion gallons by 2012). There were numerous subsidies and tax breaks for most forms of energy, including petroleum and gas, and the petroleum industry got new incentives to drill in the Gulf of Mexico.

Ethanol: A clear, colorless, flammable oxygenated hydrocarbon. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. It is used in the United States as a gasoline octane enhancer and oxygenate (blended up to 10 percent concentration). Ethanol can also be used in high concentrations (E85) in vehicles designed for its use.

Fixed Costs: Costs that do not change when the quantity of output changes during a particular time period.

Fluid Cracking: The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil. Catalytic cracking processes fresh feeds and recycled feeds.

Fossil Fuels: An energy source formed in the earths crust from decayed organic material. The common fossil fuels are petroleum, coal, and natural gas.

Grass Roots Refinery: A refinery built from the ground up on a site which has no existing refinery infrastructure on it or surrounding it.

Gross Profit Margin: The ratio of sales minus the cost of goods sold divided by the total sales. This measure looks at profits as a percent of all inputs into the profit generating function.

Hydrocracking: A refining process that uses hydrogen and catalysts with relatively low temperatures and high pressures for converting middle boiling or residual material to high octane gasoline, reformer charge stock, jet fuel, and /or high grade fuel oil. The process uses one or more catalysts, depending on product output, and can handle high sulfur feedstocks without prior desulfurization.

Hydrotreating: A refining process for treating petroleum fractions from atmospheric or vacuum distillation units (e.g., naphthas, middle distillates, reformer feeds, residual fuel oil, and heavy gas oil) and other petroleum (e.g., cat cracked naphtha, coker naphtha, gas oil, etc.) in the presence of catalysts and substantial quantities of hydrogen. Hydrotreating includes desulfurization, removal of substances (e.g., nitrogen compounds) that deactivate catalysts, conversion of olefins to paraffins to reduce gum formation in gasoline, and other processes to upgrade the quality of the fractions.

Integrated International Oil Companies: Oil companies which have both Upstream assets, Downstream assets, and Chemical assets in their portfolios. The study focuses on BP, ChevronTexaco, ConocoPhillips, ExxonMobil, and Shell.

International Energy Agency (IEA): The IEA is a specialized agency of the OECD and acts as energy policy advisor to the 26 OECD member nations. The IEA was proposed by the United States and established in 1974 in response to the Arab Oil Embargo of the 1973.

Jones Act (Merchant Marine Act): Law enacted by Congress in 1920 that requires U.S.-flagged vessels to be built in the United States, owned by U.S. citizens, and documented under the U.S. laws; documented meaning "registered, enrolled, or licensed under the laws of the United States." In addition, all officers and 75 percent of the crew must be U.S. citizens. All vessels that satisfy these requirements comprise the "Jones Act fleet".

Liquefied Petroleum Gases: A group of hydrocarbon-based gases derived from crude oil refining or natural gas fractionation. They include ethane, ethylene, propane, propylene, normal butane, butylene, isobutane, and isobutylene. For convenience of transportation, these gases are liquefied through pressurization.

Lube Processing: Development of substances used to reduce friction between bearing surfaces, or incorporated into other materials used as processing aids in the manufacture of other products, or used as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases.

Maya Crude: A heavy crude with an API gravity of 22 from Mexico. It is typically viewed as the benchmark heavy sour crude on the USGC.

MTBE (methyl tertiary butyl ether): An ether intended for gasoline blending to improve octane ratings. Being phased out of the U.S. gasoline supply in 2006 in accordance with the Energy Policy Act of 2005.

Naphthas: Refined or partly refined light distillates with an approximate boiling point range of 27 degrees to 221 degrees Centigrade. Blended further or mixed with other materials, they make high-grade motor gasoline or jet fuel. Also, used as solvents, petrochemical feedstocks, or as raw materials for the production of town gas.

Natural Gas Liquids (NGL): Light hydrocarbons such as ethane, propane, butanes and pentanes that are recovered as a byproduct of the process to produce natural gas from wells. The NGL's are utilized by refineries as a feedstock or gasoline blendstock, and by petrochemical companies, and others who market NGLs (e.g. propane distributors, etc).

NYMEX 3-2-1 Crack Spread: The price of 2 gasoline contracts and 1 heating oil futures contract minus 3 crude oil contracts; derived from the fact that 3 barrels of oil will theoretically produce 2 barrels of gasoline and 1 barrel of heating oil/distillate in a U.S. refinery. The value of the spread represents the difference in valuation by the markets and is a measure of refinery gross margin.

Organization for Economic Cooperation and Development (OECD): An international organization established in 1960 as the successor to the European Marshall Plan Agency, functions as the industrialized countries cooperation approach to deal with mutual economic, social, trade, finance and related issues. Its membership comprises about 30 member countries including the United States, Canada, Japan, and Europe.

OPEC (Organization of the Petroleum Exporting Countries): An organization founded in Baghdad, Iraq, in September 1960, to unify and coordinate members' petroleum policies. OPEC members' national oil ministers meet regularly to discuss prices and, since 1982, to set crude oil production quotas. Original OPEC members include Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela. Between 1960 and 1975, the organization expanded to include Qatar (1961), Indonesia (1962), Libya (1962), the United Arab Emirates (1967), Algeria (1969), Nigeria (1971), Ecuador (1973), and Gabon (1975). Ecuador withdrew in December 1992, and Gabon withdrew in January 1995. Although Iraq remains a member of OPEC, Iraqi production has not been a part of any OPEC quota agreements since March 1998.

Petroleum and Coal Products Manufacturing: NAICS code 324. Its definition stipulates: "The Petroleum and Coal Products Manufacturing subsector is based on the transformation of crude petroleum and coal into usable products. The dominant process is petroleum refining that involves the separation of crude petroleum into component products through such techniques as cracking and distillation. In addition, this subsector includes establishments that primarily further process refined petroleum and coal products and produce products, such as asphalt coatings and petroleum lubricating oils.

Petrochemical Integration: An opportunity for refiners to convert fuel products into petrochemicals. Petrochemicals are organic and inorganic compounds and mixtures that include but are not limited to organic chemicals, cyclic intermediates, plastics and resins, synthetic fibers, elastomers, organic dyes, organic pigments, detergents, surface active agents, carbon black, and ammonia.

Price to Earnings Ratio: Price of a stock divided by its earnings per share.

Profit: The excess of revenues over outlays in a given period of time (including depreciation and other non-cash expenses).

Petroleum Administrative Defense Districts (PADDs): The United States is divided into five regional districts used for data collections and analysis.

1. PADD 1 includes the entire East Coast, from Maine to Florida. It has the most population and the more petroleum consumption. This PADD is further divided into 3 sub districts: PADD 1A- New England; PADD 1B-Central Atlantic; and PADD 1C- Lower Atlantic.
2. PADD 2 includes the Midwest.
3. PADD 3 includes the Gulf Coast. This region is the main oil supply for the United States.
4. PADD 4 includes the Rocky Mountain, and is sparsely populated resulting in a long distribution network.
5. PADD 5 includes the West Coast. Population is large and consumption is high, largely from California. California also has imposed a large number of environmental specifications that separate PADD V from the rest of the country.

RBOB: An acronym for Reformulated Gasoline Blendstocks for Oxygenate Blending. Unfinished motor gasoline that meets the requirements of the RBOB regulations promulgated by the U.S. Environmental Protection Agency. This base gasoline is designed to be blended with an oxygenate in order to comply with EPA's finished reformulated gasoline regulations.

Refinery Capacity Utilization: Ratio of the total amount of crude oil run through crude oil distillation units to the operable capacity of these units.

Refinery Complexity: An oil refinery's ability to process feedstocks, such as heavier and higher sulfur content crude oils, into value-added products. Generally, the higher the complexity and more flexible the feedstock slate, the better positioned the refinery is to take advantage of the more cost effective crude oils, resulting in incremental gross margin opportunities for the refinery.

Refinery Margins: Refining margins are the difference in value between the products produced by a refinery and the value of the crude oil used to produce them. Refining margins will thus vary from refinery to refinery and depend on the price and characteristics of the crude used.

Refinery Yield: Refinery yield (expressed as a percentage) represents the percent of finished product produced from input of crude oil and net input of unfinished oils. It is calculated by dividing the sum of crude oil and net unfinished input into the individual net production of finished products. Before calculating the yield for finished motor gasoline, the input of natural gas liquids, other hydrocarbons and oxygenates, and net input of motor gasoline blending components must be subtracted from the net production of finished gasoline.

Reformers: A processing unit in a refinery that uses controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules, thereby converting paraffinic and naphthenic type hydrocarbons (e.g., low octane gasoline boiling range fractions) into petrochemical feedstocks and higher octane stocks suitable for blending into finished gasoline.

Renewable Fuels Standard (RFS): Included in the Energy Policy Act of 2005 and mandated the use of 4 billion gallons of renewable fuels starting in 2006, and 7.5 billion gallons in 2012.

Resource Rents: An economic term for profit which derives from the exploitation of natural resources.

Return on Assets: The ratio of net income (i.e., profit) to total company or industry assets and is a measure of how efficiently assets are being deployed to generate income.

Return on Capital Employed (ROCE): A company's earnings before interest and taxes (EBIT) divided by the difference of its total assets and current liabilities

Return on Equity: The measure of profit relative to the shareholder equity.

Secondary Units: Processing units that focus on the downstream sector or petroleum products. These units include (for example) delayed cokers, catalytic crackers, alkylation units and catalytic hydrotreaters and hydrocrackers.

West Texas Intermediate (WTI) Crude: A type of crude oil used as a benchmark in oil pricing and the underlying commodity of New York Mercantile Exchange's oil futures.

ULSD: Ultra Low Sulfur Diesel, with sulfur content of 15 parts per million (ppm) maximum requirement.

U.S. Gulf Coast or West Coast Crack Spread: Similar definition to Crack Spread above, with prices used based on the U.S. Gulf Coast or West Coast spot market.

Upstream: The exploration and production sectors in the oil and gas industry.

Variable Operating Costs: Day-to-day expenses incurred in running a business that change when the quantity of output changes.

Vessel Bunkering: Includes sales for the fueling of commercial or private boats, such as pleasure craft, fishing boats, tugboats, and ocean-going vessels, including vessels operated by oil companies. Excluded are volumes sold to the U.S. Armed Forces.

VLCC: Very large crude carriers, typically able to carry 2 million barrels of crude oil.

Yield: Refinery yield (expressed as a percentage) represents the percent of finished product produced from input of crude oil and net input of unfinished oils. It is calculated by dividing the sum of crude oil and net unfinished input into the individual net production of finished products. Before calculating the yield for finished motor gasoline, the input of natural gas liquids, other hydrocarbons and oxygenates, and net input of motor gasoline blending components must be subtracted from the net production of finished aviation gasoline.

Abbreviations and Acronyms

bgy	Billions of gallons per year
TBD	Thousands of barrel per day
cpg	Cents per gallons

ENDNOTES

[1] EIA, U.S. Department of Energy, Petroleum Chronology of Events 1970-2000, available on the web, http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/chronology/petroleumchronology2000.htm#T_8_

[2] Note that the report will refer to the "United States" capacity, demand, etc. inclusive of California unless otherwise cited in the text.

[3] Grass Roots means a refinery built on a new location from the ground up

[4] Conversion level is the ability of a refinery to convert crude oil into clean products (gasolines and distillates). To process heavy California crude into clean products requires high conversion capacity, leading to high complexity.

[5] Source: EIA 2006 Refinery Capacity report, Table 4; Chevron Richmond and El Segundo

[6] Secondary units are processing units that focus on the downstream sector or petroleum products. These units include (for example) delayed cokers, catalytic crackers, alkylation units and catalytic hydrotreaters and hydrocrackers.

[7] Residual oil is the portion of crude oil that boils at over 1000 degrees Fahrenheit. Residual can be sold as bunker fuel or as residual oil for power generation, with addition of stocks to lower viscosity. Most residual oil in the U.S. is processed in delayed coking units.

[8] Ratable means simply that the logistics of delivering crude and feedstocks, and shipping products is smooth and efficient. Disruptions in supply related to delays in cargo arrivals, pipeline outages, etc create shortages or even surplus conditions that can impact supply reliability.

[9] The crack spreads assume a nominal product yield of 2 barrels of gasoline and 1 barrel of distillate for every 3 barrels of crude, thereby providing a measure of refinery gross margin.

[10] Unfinished Feedstocks include naphtha, gas oil, and kerosines that are imported for processing in secondary processing units in the refinery.

[11] Source: CEC Staff calculations from domestic and foreign crudes processed

[12] Total Acid Number; a measure of a crude oil's ability to corrode piping and mechanical equipment

[13] Maintenance requirements, energy consumption, manpower, chemicals, etc.

[14] The size of the economy is measured as the Gross State Product (GSP) reported by the U.S. Census Bureau.

[15] EIA data on Refinery Capacity for January 1, 2006; adjusted to include all hurricane related idle capacity as operational

[16] ICFI review of company announcements and published reports; primarily projects by ConocoPhillips, Marathon, Cenex, Tesoro, United and Frontier

[17] See Exhibit 1.12

[18] See Renewable Fuels Association. Ethanol Biorefinery Locations, 10 August 2006 http://www.ethanolrfa.org/industry/locations/; the RFA website continually updates during the year.

[19] Assumed high fuel price and no GHG standard growth rate.

[20] Move AZ Report, *Arizona Long Range Transportation Plan,* Chapter 8, Goods Movement http://www.moveaz.org/

[21] As per Gillette memorandum, dated 07-27-06.

[22] California Energy Commission, February, 2005, *CEC Workshop on Petroleum Infrastructure Best Permitting practices,* Report by Western States Petroleum Association

[23] California Energy Commission, October, 2003, *Permit Streamlining for Petroleum product Storage,* Report by ICF Consulting, pg 9-10

[24] In fact, ROE = ROCE + (ROCE - i) x D/E, where i equals the market interest rate and D/E equals total debt divided by total equity.

[25] A comparison of ROCE vs ROACE with average capital employed over a year showed virtually identical results (under 0.5% difference in ROCE vs ROACE)

[26] NAICS – North American Industry Classification System

[27] Integrated means that the companies have “Upstream, or Exploration & Production” assets, including natural gas, “Downstream, or Refining and Marketing” assets, as well as “Chemical or other” assets in their portfolio

[28] Crack Spread is a measure of the value of the refinery products minus the cost of the crude, or the gross margin. In the United States, the typical full upgrading refinery produces fuel products in a ratio of about 2 barrels of gasoline and one barrel of jet/distillate per barrel our of every 3 barrels of crude. Although not exact, the crack spread “yardstick” takes the sum of 2x gasoline spot price plus 1x distillate spot price and subtracts 3x crude price to give a general margin indicator of refinery gross margin (known as a 3-2-1 crack spread)

[29] ROCE calculation from Census Bureau data was done by dividing EBIT by (Total Assets – Current Liabilities)

[30] USGC is the United States Gulf Coast market for commodities; Maya is a heavy, high sulfur crude oil from Mexico; WTI is West Texas Intermediate crude, a light sweet crude; ANS is Alaskan North Slope, a medium heavy, medium sulfur crude processed primarily on the West Coast

[31] Ernst & Young LLP, prepared for American Petroleum Institute. Investment and Other Uses of Cash Flow by the Industry, 3 February 2006Located on API’s website at http://api-ec.api.org/about/index.cfm?bitmask=742FB6E2-B191-4F77-B91FEC841521C671#

APPENDIX B

REFINERY OUTAGES AND PROCESS UNITS

REFINERY OUTAGES AND PROCESS UNITS

Regular maintenance of refinery process units is necessary to maintain yields and reduce the risk of catastrophic failures. Refineries with enough complexity to produce large volumes of gasoline, diesel, and jet fuel are made up of many units; however, the units which appear to affect production the most are crude units, fluid catalytic cracking units (FCC units), hydrocracking units (hydrocrackers) and diesel hydrotreaters.

This analysis focuses on these units and attempts to determine if there are any seasonal patterns for maintenance events. It describes how production may be affected when a unit is undergoing maintenance or repair.

Table B-1 illustrates the severe conditions under which these units operate.[i]

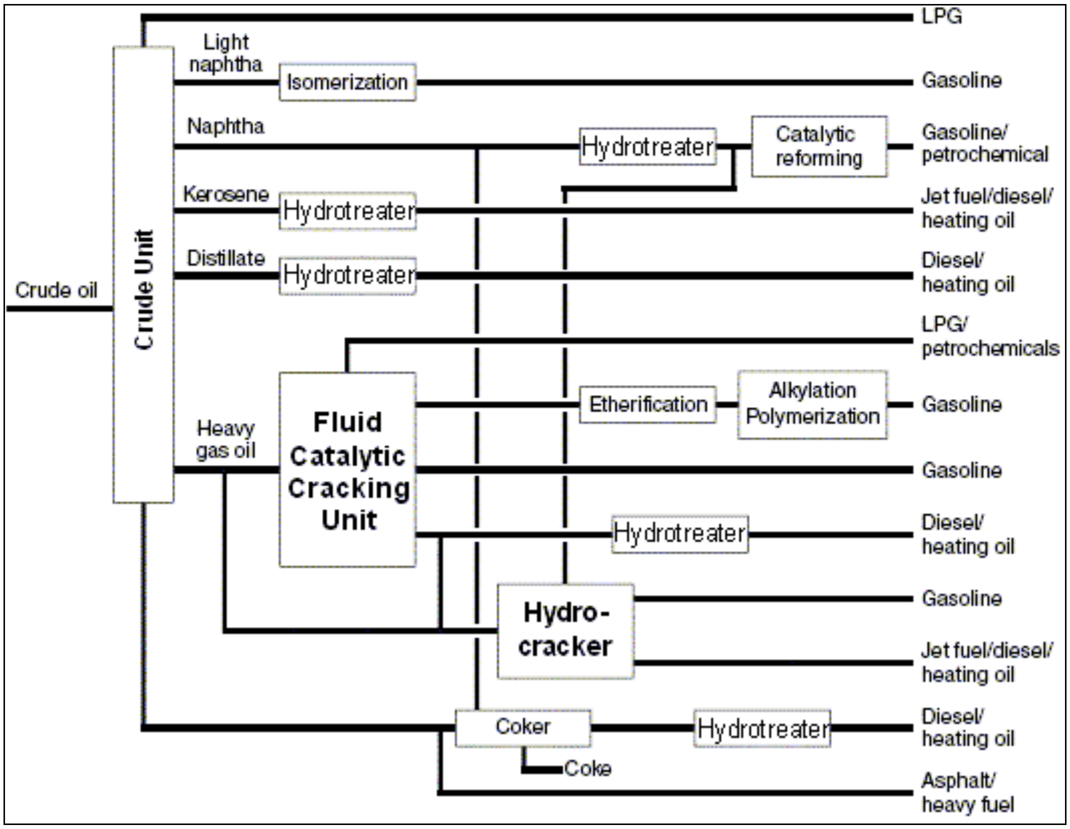
Table B-1: Process Unit Operating Conditions

Unit	Operating Temperature	Operating Pressure
Crude Unit	650° to 700° F	Slightly above atmospheric pressure
FCC Unit	750°-1500° F	1,000-2,000 psi
Diesel Hydrotreater	600° to 800° F	1,000 psi
Hydrocracker	750°-1500° F	1,000-2,000 psi

In a crude unit, heat is applied to crude oil to separate the oil into various components which are then sent to other refinery process units. FCC units process feedstock in the presence of a catalyst at high pressure and temperature. Hot catalyst in the FCC unit reacts with the feedstock to “crack,” or break apart, large molecules into smaller molecules in the range of gasoline and diesel fuels. Hydrocracking units operate similarly, but hydrogen is fed into the reactor during operation. Diesel hydrotreaters remove sulfur, nitrogen, and metals by passing the feedstock through a catalyst in the presence of hydrogen.

Figure B-1 illustrates how refinery units are interconnected.[ii]

Figure B-1



For this analysis, an "outage event" is defined as an individual refinery processing unit that is shut down or operated at significantly reduced rates due to either planned or unplanned circumstances, typically for maintenance or repair. The Energy Commission has compiled information on refinery outage events since July 2004. Refinery outage information is either reported by the industry or determined by staff investigations of published news reports or changes in refinery inputs and production.

Table B-2 shows the number of events included in this analysis for each type of processing unit for both planned and unplanned events. The data is based on the state's 14 gasoline and diesel producing refineries. Refineries that do not produce gasoline or diesel fuel are not included in the analysis.

Table B-2: Observed California Refinery Outage Events January 2005 through June 2006

Event Type	Planned	Unplanned	Total
Crude Unit	10	5	15
FCC Unit	8	9	17
Diesel Hydrotreater	6	6	12
Hydrocracker	6	5	11

Effects of Maintenance on Production

Crude Processing Unit

Unplanned maintenance on crude processing units has a very dramatic impact on production compared to other refinery unit outages. On average, crude oil inputs during an unplanned maintenance event decline by 39 percent. With reduced inputs of crude oil, other refinery units are either shut down or run at reduced rates. During either planned or unplanned crude processing unit events, refiners may purchase intermediate products[iii] on the open market or use existing inventories in order to maintain production of finished products.

Table B-3 shows the average percentage of reduced production of finished products and crude oil inputs for 15 maintenance events involving crude units between January 2005 and June 2006. Unplanned crude unit events have a significantly greater impact on production compared to planned maintenance events.

Table B-3: Crude Processing Unit Maintenance Events January 2005 through June 2006

Average Percentage Effect on Production and Oil Inputs			
Type of product/input:	**Planned events**	**Unplanned events**	**All events**
Gasoline Production	-9%	-18%	-12%
Diesel Production	-14%	-50%	-28%
Jet Fuel Production	-21%	-48%	-31%
Oil Input	-26%	-39%	-31%

Fluid Catalytic Cracking Units

Fluid catalytic cracking (FCC) units experience more maintenance events than any other refinery processing unit during the period from January 2005 through June 2006. These maintenance events significantly affect gasoline production more than diesel or jet fuel production.

Table B-4 shows the average percentage of reduced production of finished products and crude oil inputs for 17 maintenance events involving FCC units between January 2005 and June 2006.

Table B-4: FCC Unit Maintenance Events
January 2005 through June 2006

Average Percentage Effect on Production and Oil Inputs			
Type of product/input:	**Planned events**	**Unplanned events**	**All events**
Gasoline Production	-22%	-33%	-28%
Diesel Production	1%	-20%	-10%
Jet Fuel Production	-9%	-12%	-11%
Oil Input	-3%	-4%	-4%

Diesel Hydrotreater

Maintenance on diesel hydrotreaters largely impacts diesel fuel production. During some diesel hydrotreater maintenance events, refineries have been observed to increase production of jet fuel for periods where diesel hydrotreaters are shut down. Jet fuel is a distillate similar to diesel fuel but with a less stringent sulfur specification (1,000-3,000 parts per million [ppm]) compared to the current maximum limit of 15 ppm sulfur for on-road diesel fuel in California.

In June of 2006, California refineries were required to begin producing an ultra-low sulfur diesel fuel with a maximum sulfur content of 15 ppm. Many refineries have had to upgrade their diesel hydrotreaters in order to meet the new specification. Most of this maintenance took place in late 2005 and early 2006.

Table B-5 shows the average percentage of reduced production of finished products and crude oil inputs for 12 maintenance events involving diesel hydrotreaters between January 2005 and June 2006.

Table B-5: Diesel Hydrotreater Maintenance Events
January 2005 through March 2006

Average Percentage Effect on Production and Oil Inputs			
Type of product/input:	**Planned events**	**Unplanned events**	**All Events**
Gasoline Production	-20%	-21%	-20%
Diesel Production	-35%	-40%	-37%
Jet Fuel Production	0%	-37%	-15%
Oil Input	-9%	-2%	-6%

Hydrocracker Maintenance

Typically, a refinery will use a hydrocracker to produce diesel and jet fuels.

Table B-6 shows the average percentage of reduced production of finished products and crude oil inputs for 11 maintenance events involving hydrocrackers between January 2005 and March 2006[iv] (the affect on jet fuel production is not included due to confidentiality).

Table B-6: Hydrocracker Maintenance Events
January 2005 through March 2006

Average Percentage Effect on Production and Oil Inputs			
Type of product/input:	**Planned events**	**Unplanned events**	**All Events**
Gasoline Production	-17%	-13%	-16%
Diesel Production	-30%	-25%	-28%
Oil Input	-9%	-2%	-6%

Next Steps

The Fossil Fuels Office will continue to analyze and collect refinery outage information. As more data is collected, additional information about common refinery process unit outages will become available. Specifically, effects on refinery production during maintenance events involving coking units, reformer units, and several types of hydrotreaters other than diesel hydrotreaters would provide a more complete understanding of the effects of maintenance on production.

Endnotes

[i] Operational Safety and Health Administration Technical Manual Section IV Chapter 2. [http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html].

[ii] Adapted from *New Forces at Work in Refining: Industry Views of Critical Business and Operations Trends*. D.J. Peterson, Sergej Mahnovski.

[iii] Oils that have been partially processed into “fractions” which can be used as feedstock for refinery units downstream of the crude unit.

[iv] The Petroleum Industry Information Reporting Act (PIIRA) requires that company specific data be held in confidence. Jet fuel is not included in Table B-6 because there were an insufficient number of events to aggregate production data for publication.

APPENDIX C

GASOLINE MARGIN ANALYSIS, WESTERN STATES

GASOLINE MARGIN ANALYSIS, WESTERN STATES

The following figures depict a breakdown of gasoline prices between January and August of 2006 for 12 western states. The definitions for each of the price components are as follows:

- **Crude Oil** - The crude oil cost component represents the refiner's acquisition cost of crude oil. The crude oil cost component is based on the market price of Alaska North Slope crude oil. Alaska North Slope crude oil prices are used because it is "middle of the road" pricing compared to lower cost (and quality) California crude oil and the higher priced (and higher quality) West Texas Intermediate crude oil price. Vertically integrated oil companies may have lower acquisition costs due to direct ownership of oil producing fields.

- **Refiner Margin** - Refiner Margin (costs and profits) is calculated by subtracting the market price for crude oil from the wholesale price of gasoline. The result is a gross refining margin which includes the cost of operating the refinery as well as the profits for the refining company. For simplicity, the refining margins shown are based on producing one barrel of gasoline from one barrel of crude oil. No adjustments are made for other refined products.

- **Taxes** - Taxes are estimated based on various state and federal taxes applicable to gasoline purchases. These include the Federal Underground Storage Tank Fee (0.1 cent per gallon).

- **Distribution Margin** - The distribution margin is calculated by subtracting the average wholesale gasoline price and taxes from the weekly average retail sales price. Similar to the refining margin, the distribution margin also includes the costs and profits of operating the retail gas station as well as various transportation and storage fees incurred once gasoline is moved from the bulk terminal to the retailer.

Figure C-1

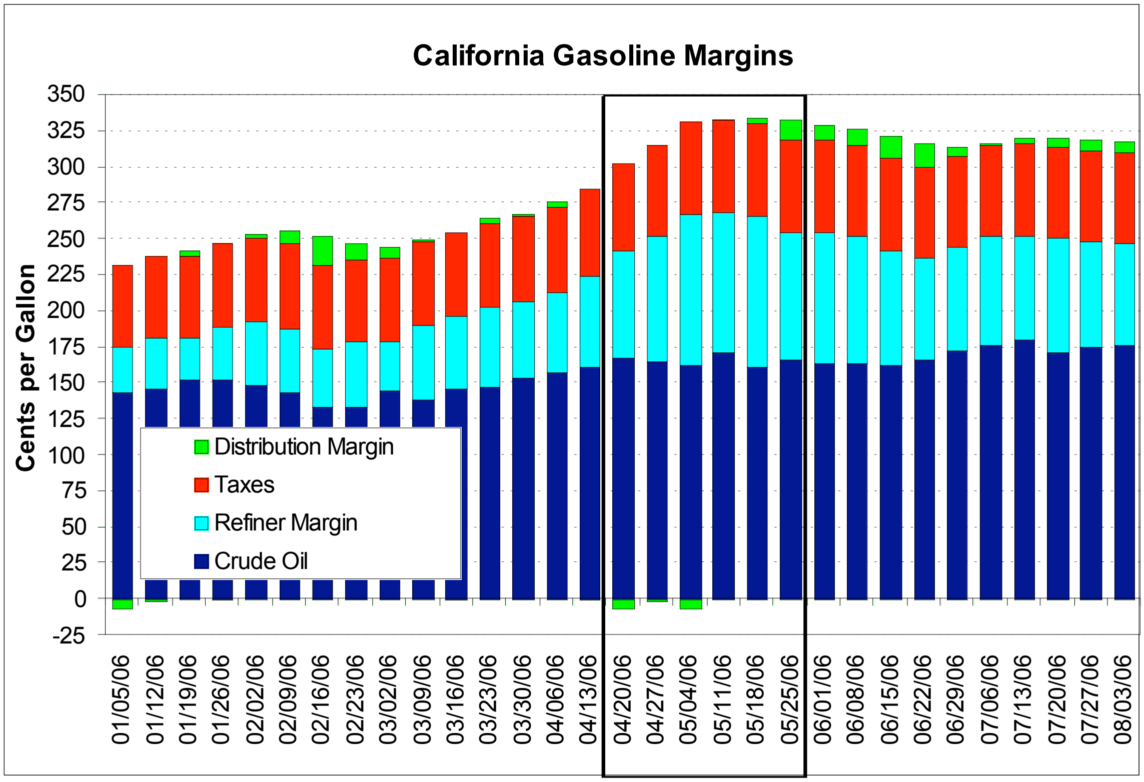


Figure C-2

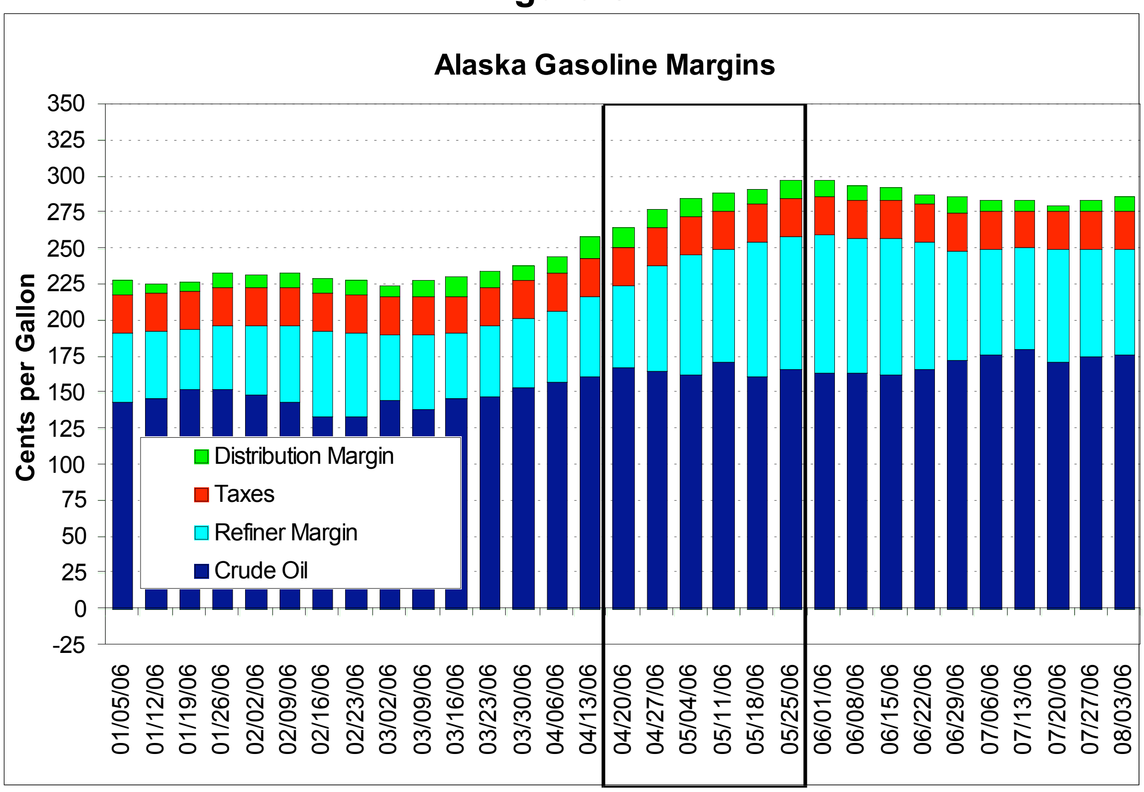


Figure C-3

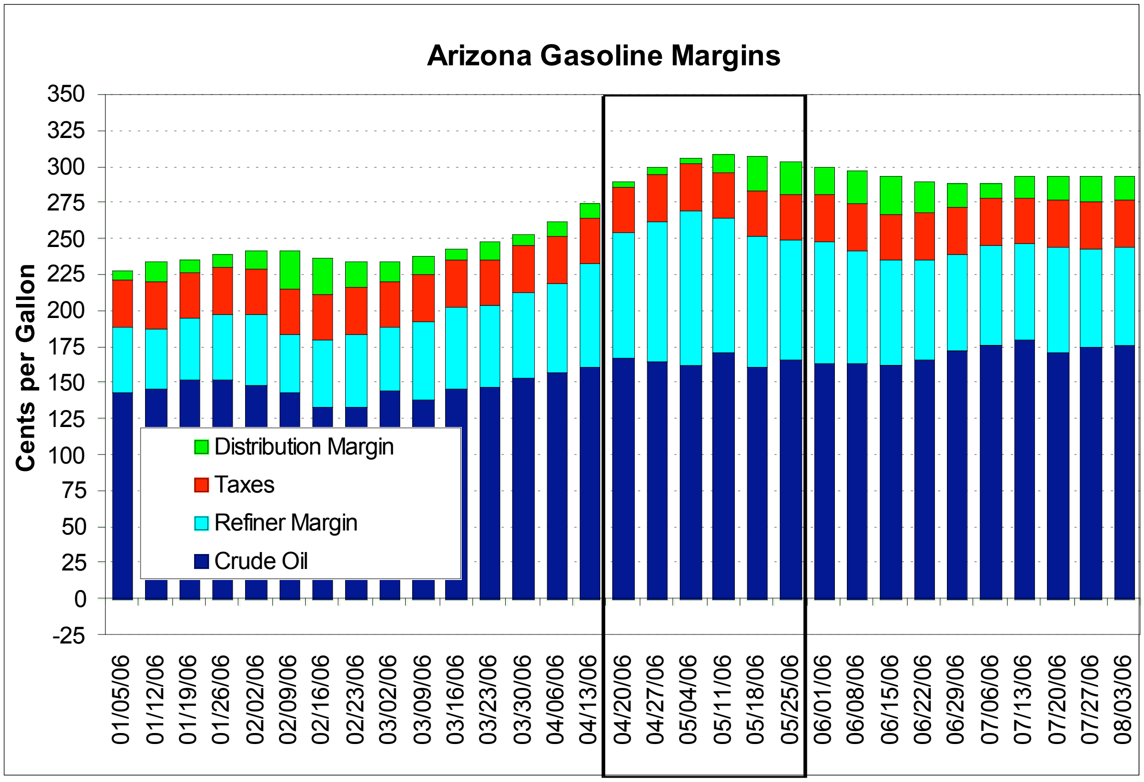


Figure C-4

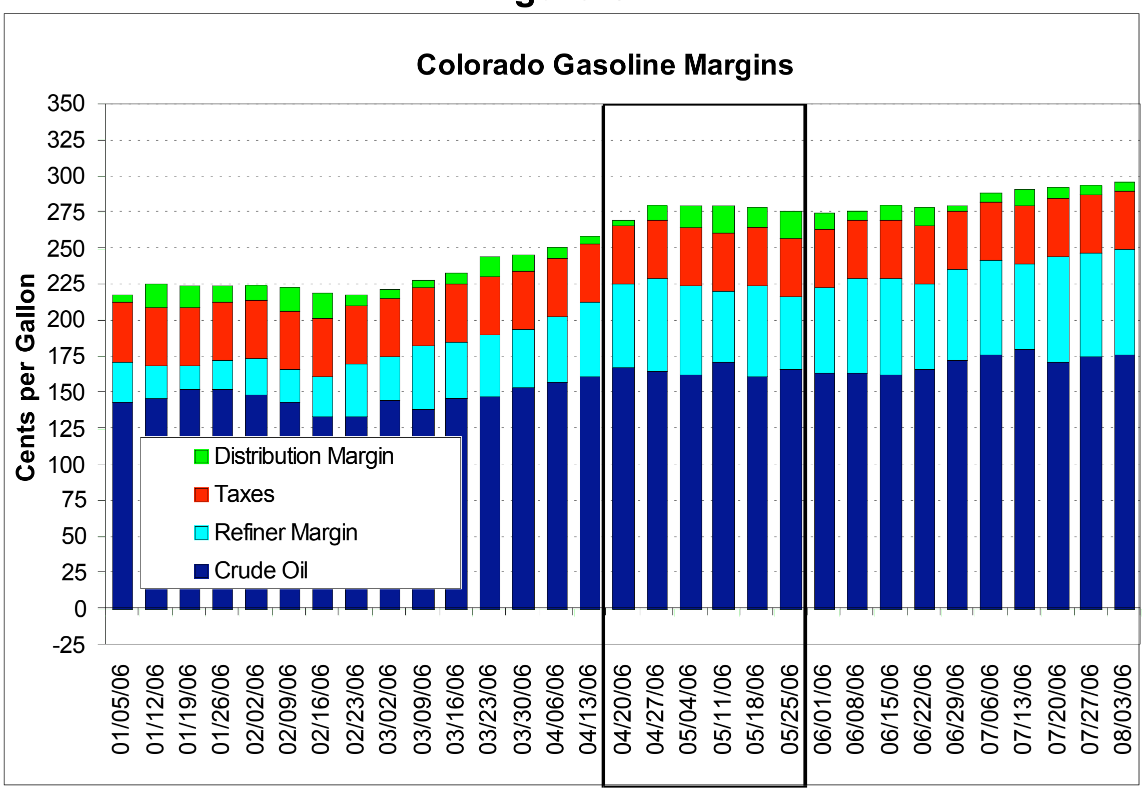


Figure C-5

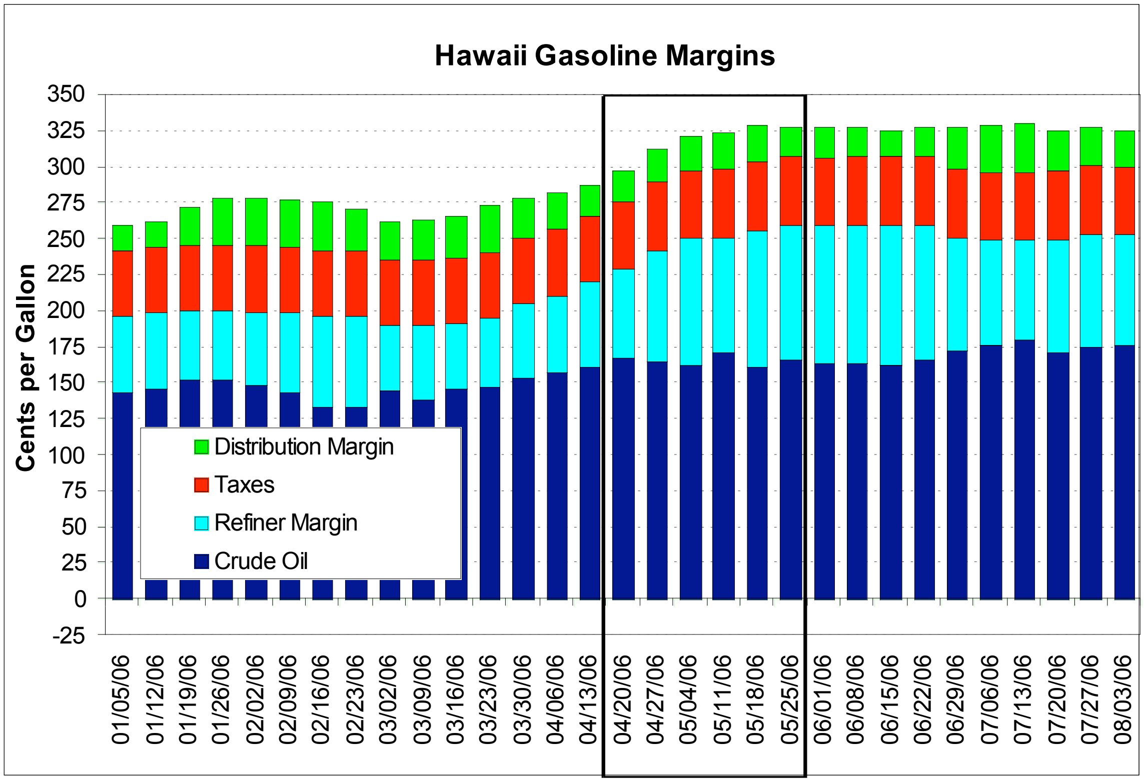


Figure C-6

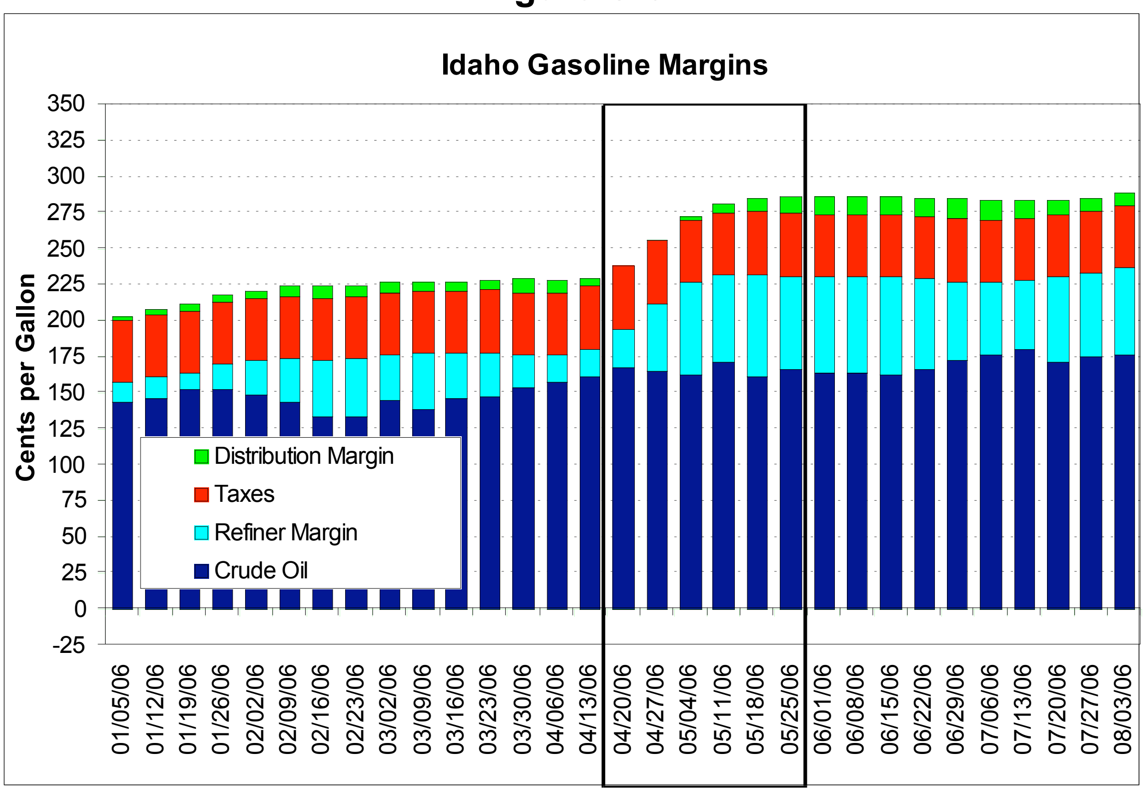


Figure C-7

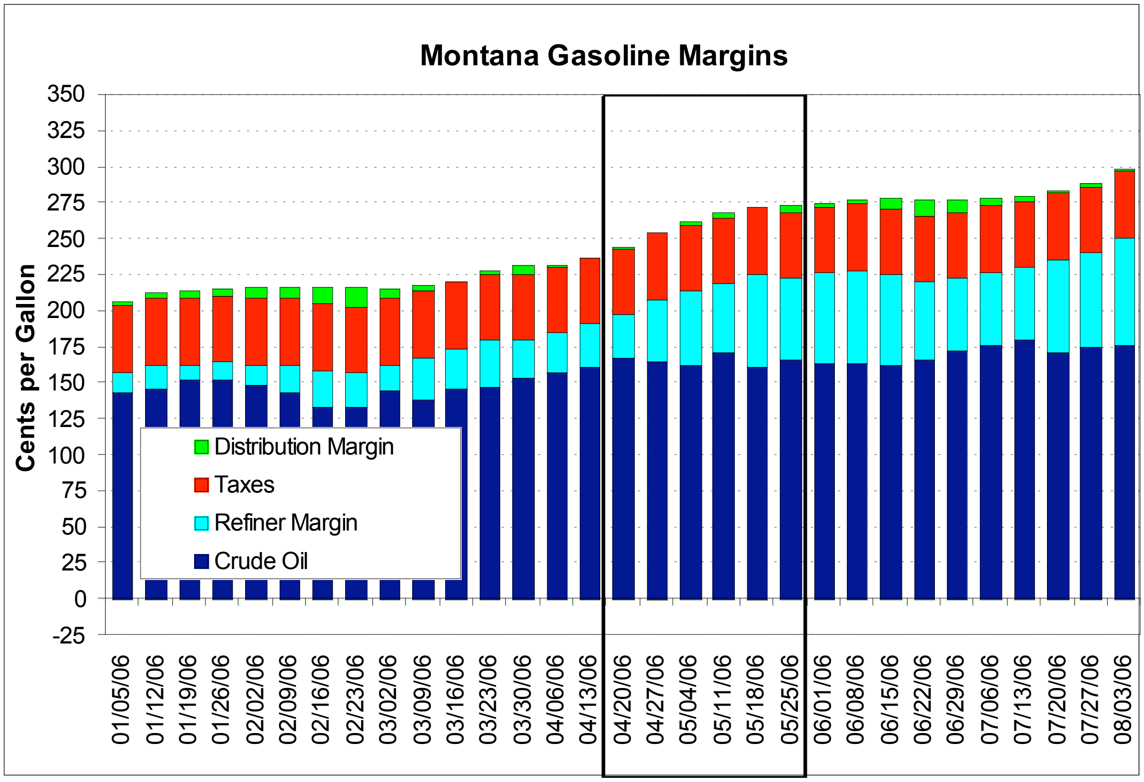


Figure C-8

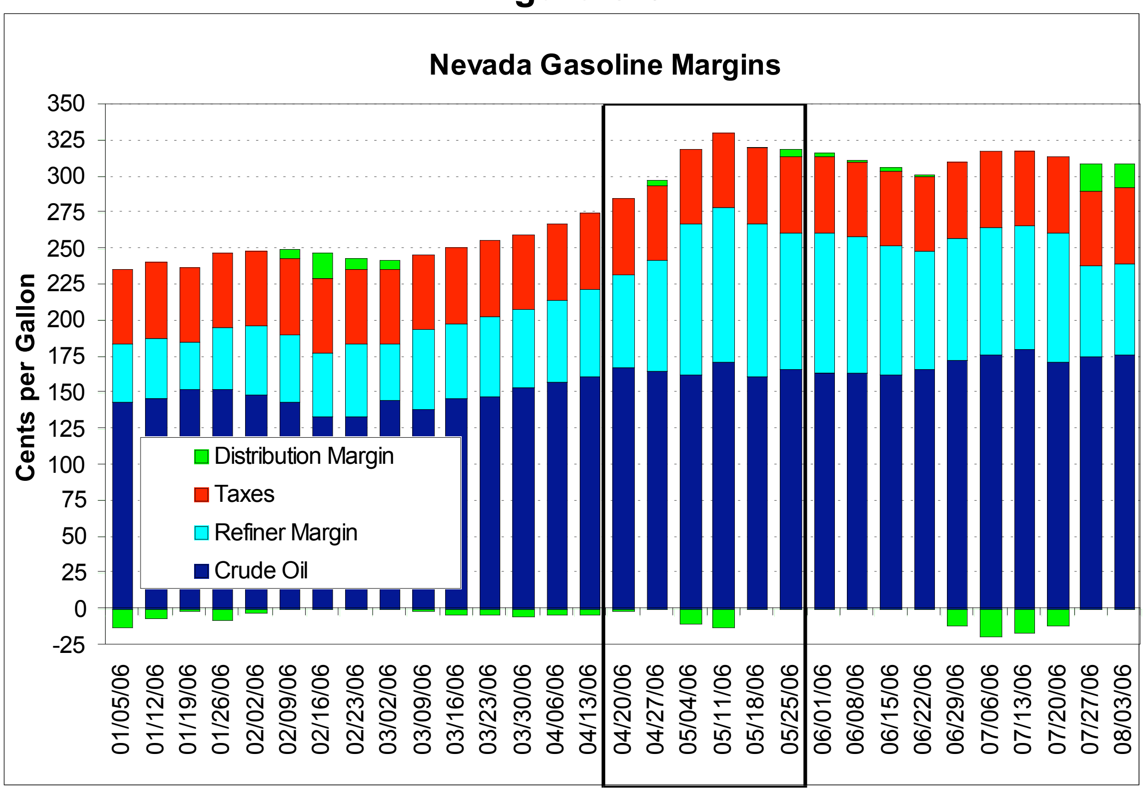


Figure C-9

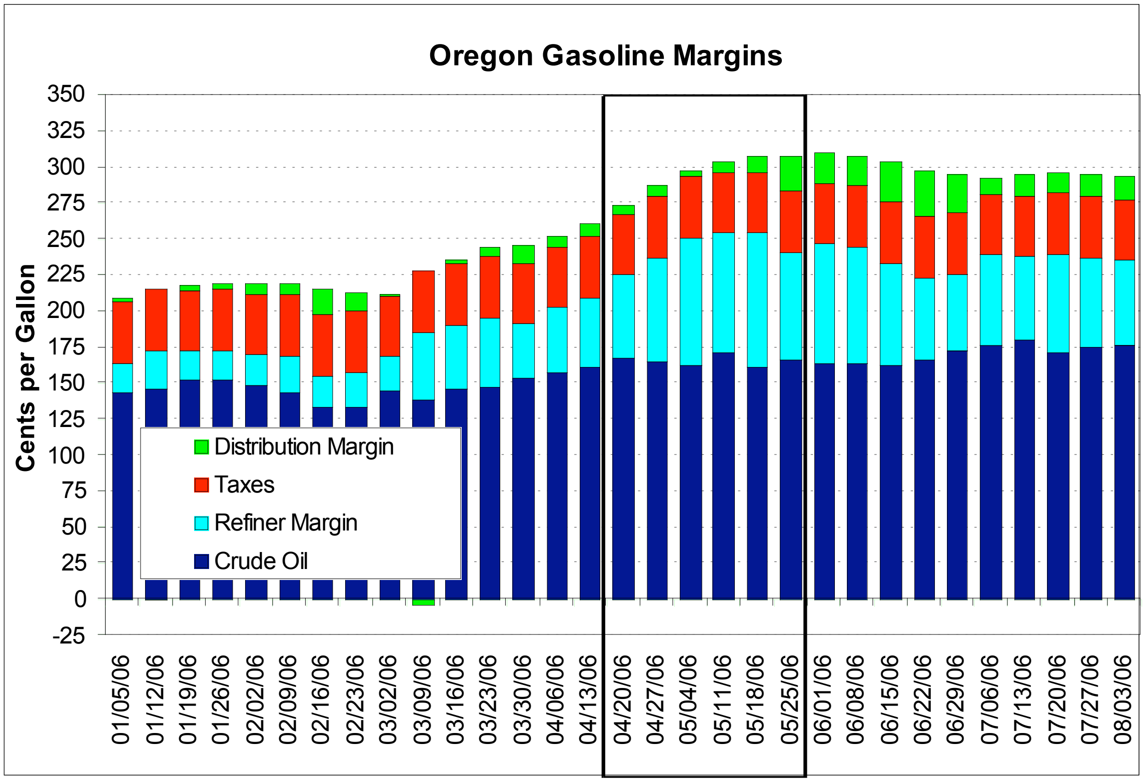


Figure C-10

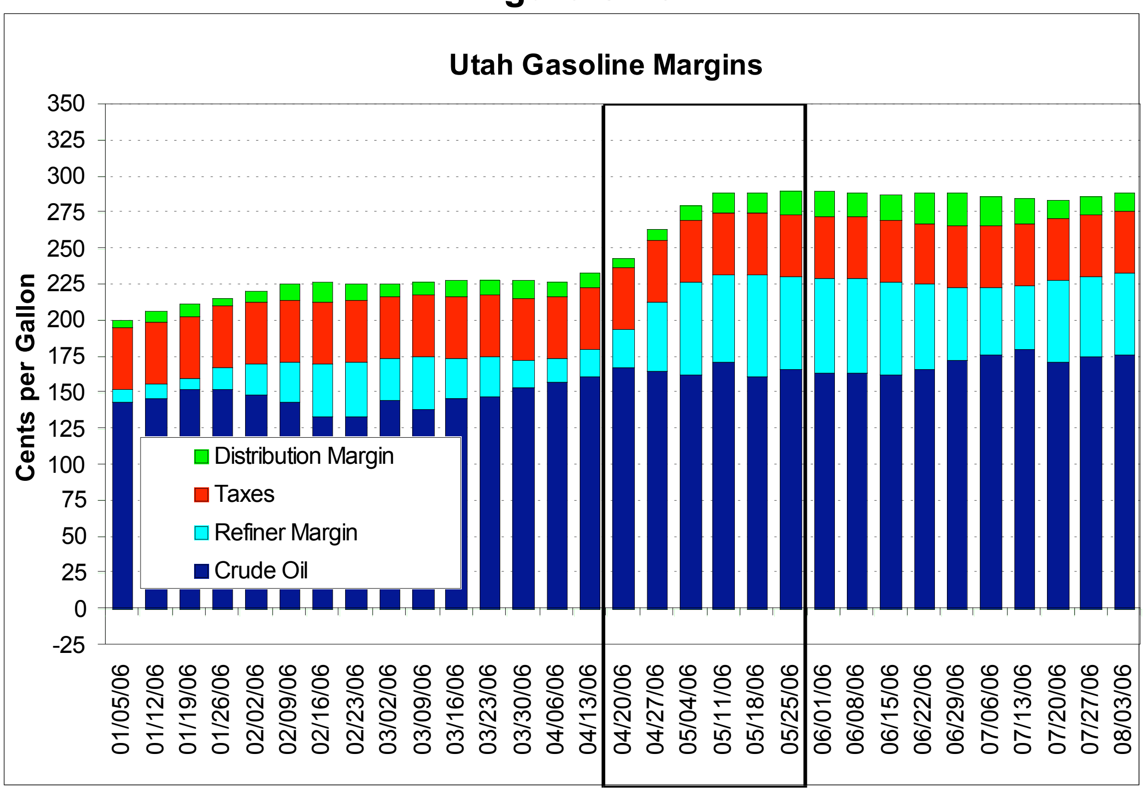


Figure C-11

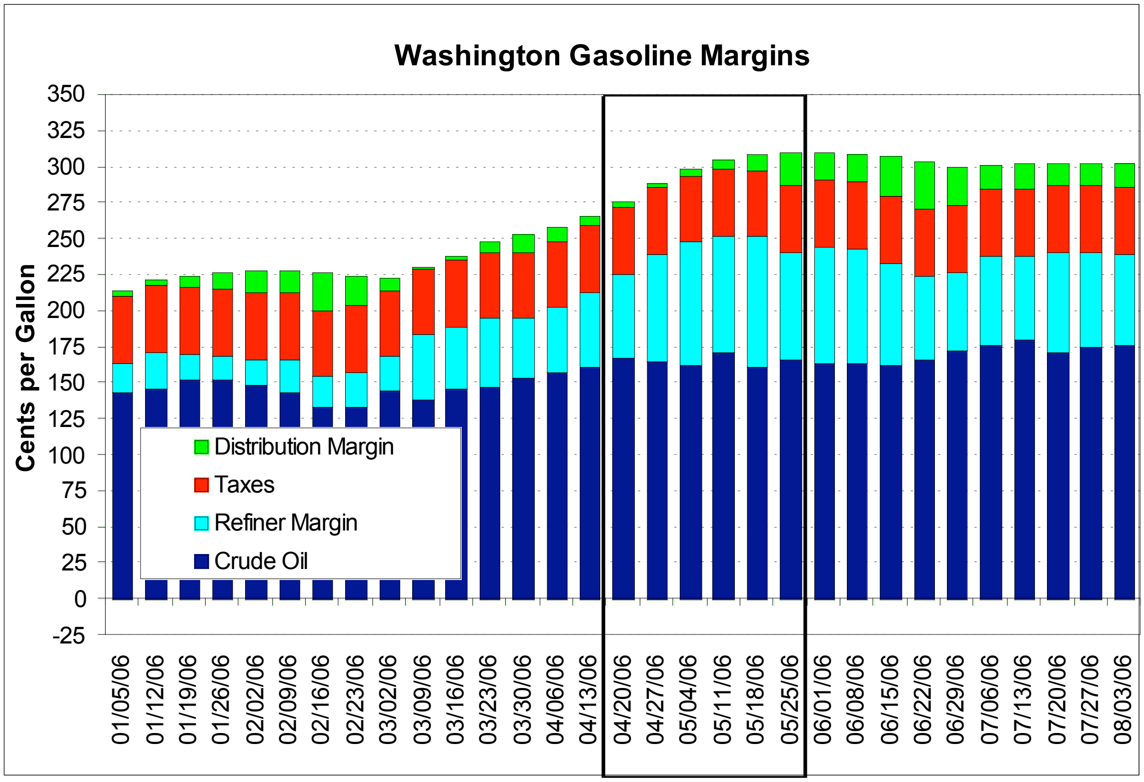
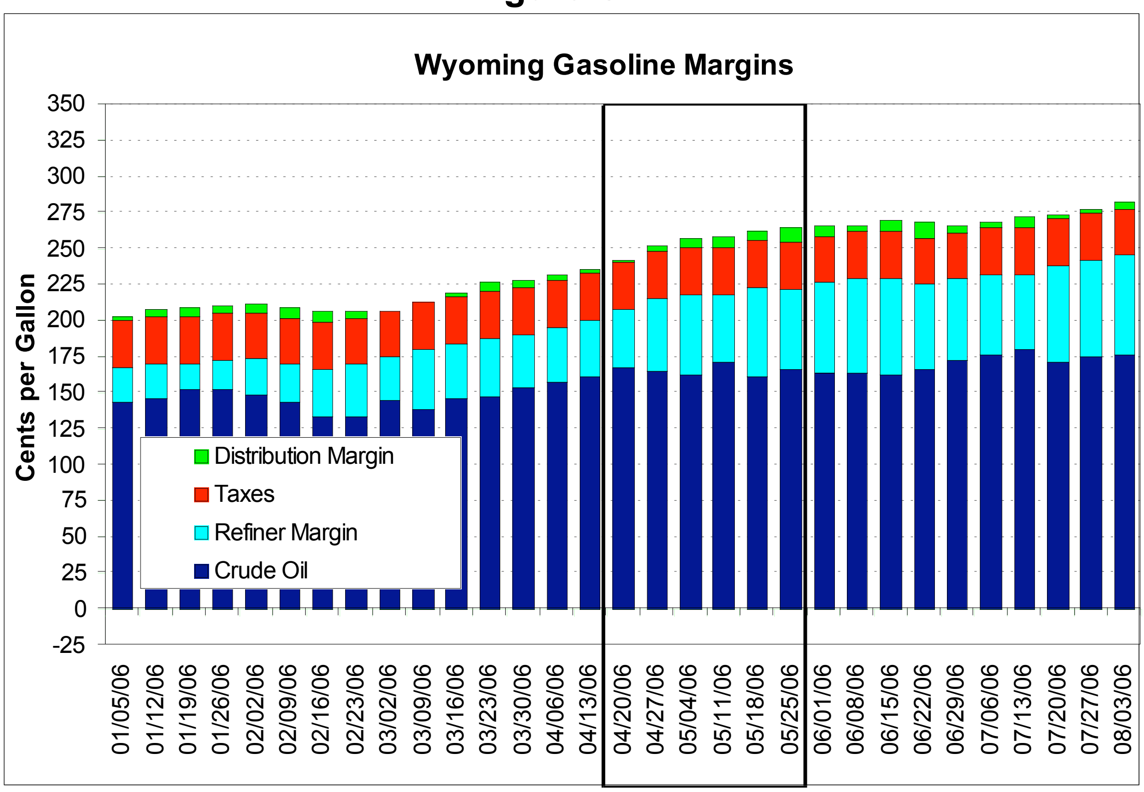


Figure C-12



APPENDIX D

RETAIL GASOLINE PRICE VARIABILITY – CALIFORNIA

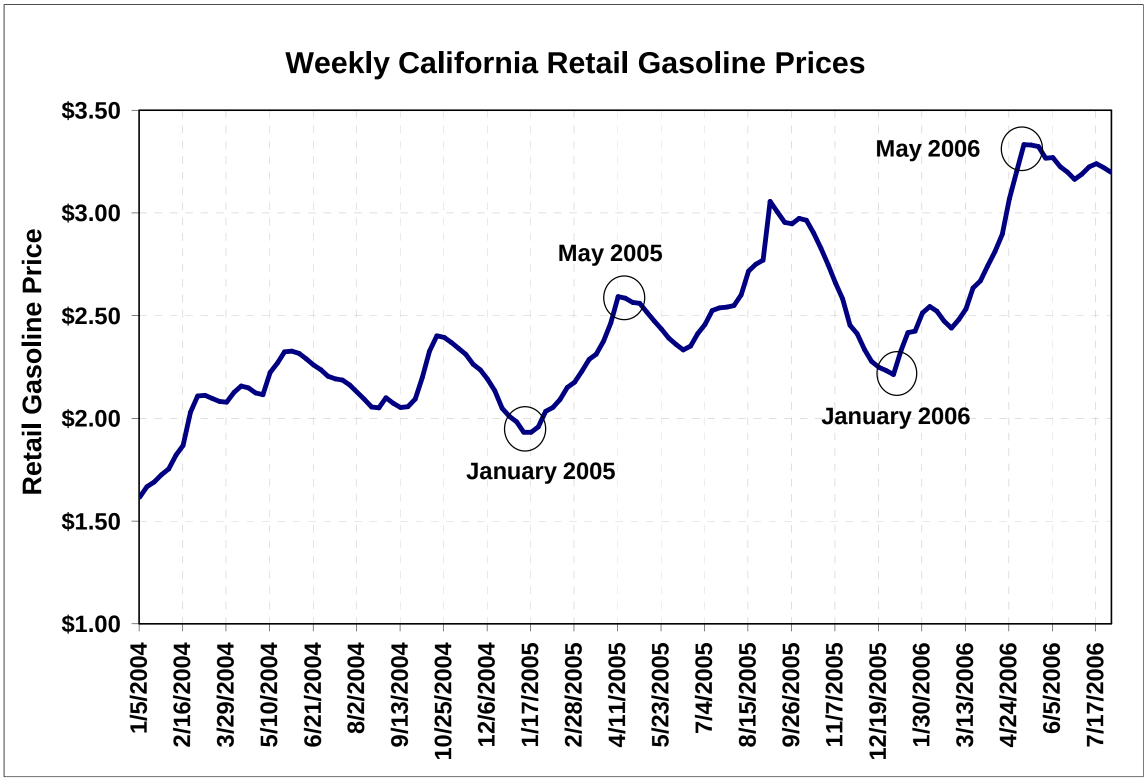
RETAIL GASOLINE PRICE VARIABILITY – CALIFORNIA

Approximately 10,000 retail fueling stations operated in California. Using data purchased from the Oil Price Information Service (OPIS), the Energy Commission analyzed daily purchase transactions at more than 7,000 stations. The OPIS data is based on records from a fleet card service provider. The OPIS retail price data includes the actual date of the transaction but does not include volumetric information. Not all stations have daily fleet card purchase transactions. In fact, very few stations of the more than 7,000 locations have complete daily data for each day of the year.

The daily records were filtered to capture data for those stations that had more than 15 transactions in a month. Stations with fewer than 15 observations per month were not used because it provides data that does not adequately or accurately price variability. The total number of stations used in the following analysis ranged from 3,747 to 4,100, depending upon the month. This reduced the total number of cities from 771 to approximately 630 throughout California.

Figure D-1 shows the weekly average retail price for gasoline in California from January 2004 through July 2006. The circles indicate the months used for the analysis. January 2005 represented of a period of low retail gasoline prices and May 2006 experienced historically high retail gasoline prices.

Figure D-1
Retail Gasoline Prices: January 2004 through July 2006



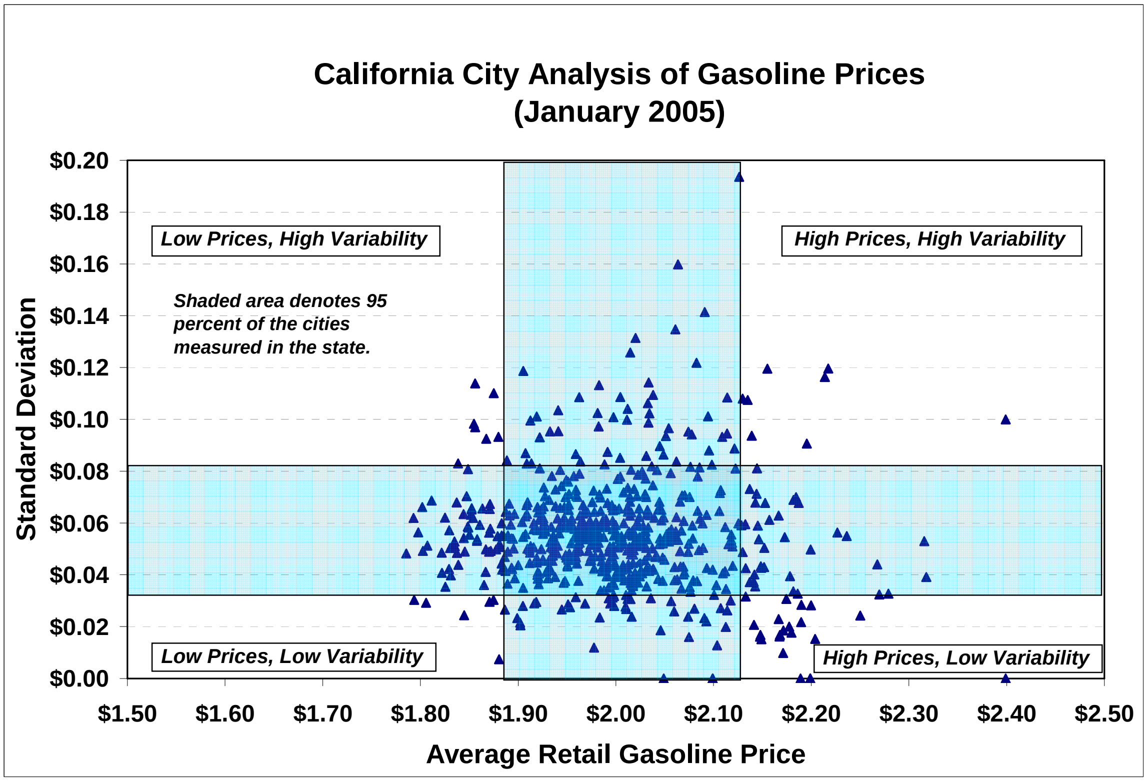
Source: CEC staff analysis of Oil Price Information Service (OPIS) data.

Underlying the average retail prices are significant regional differences in fuel prices, which cannot be observed in **Figure D-1**.

Figures D-2 through **D-5** display scatter plots that show California's retail gasoline prices by city for the months of January 2005, May 2005, January 2006, and May 2006, respectively. The months were selected to observe if there were significant differences between time periods of relatively high and low retail prices.

Each figure has two shaded regions that represent 95 percent of all cities in the dataset. Each city is plotted according to the observed average price and its standard deviation. Not having complete pricing data for any single station in each city, as well as observing that the data is not normally distributed, resulted in this approach. The lack of a normal distribution of average city prices is a result of the extreme geographical diversity within the state as well as population density and travel patterns. The use of a 95 percent ranking results in a more robust accounting for those cities that fall outside of the observed averages.

Figure D-2
Scatter Plot of California Cities: January 2005



Source: CEC staff analysis of Oil Price Information Service (OPIS) data.

The outlying cities for January 2005 are categorized as follows:

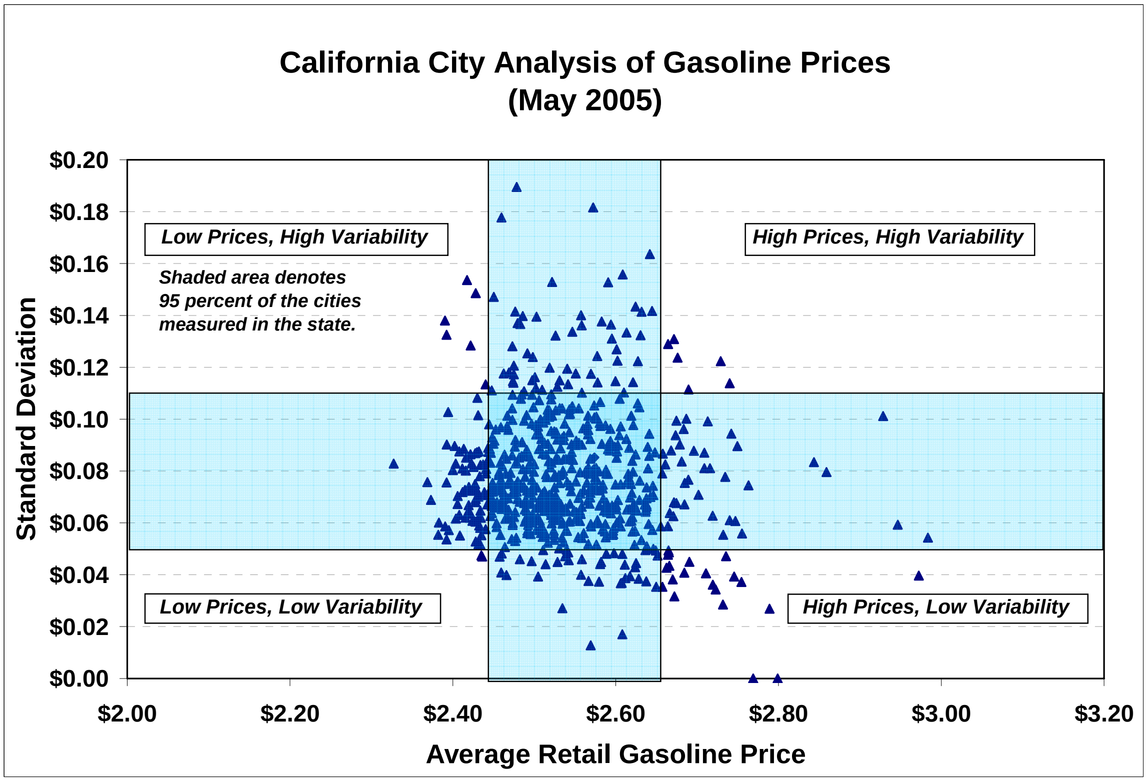
Low Prices, Low Variability:
Crows Landing, Delhi, Frazier Park, Hilmar, Hughson, and Shingle Springs.

Low Prices, High Variability:
Auburn, Byron, Gridley, Marysville, Oakdale, Suisun City, and Woodland.

High Prices, Low Variability:
Big Bear City, Blue Jay, Castella, Chester, El Segundo, Fort Jones, Garberville, Hornbrook, Maxwell, McCloud, Montague, Mount Shasta, North Palm Springs, Olancha, Pacific Palisades, Point Reyes Station, San Miguel, Shaver Lake, Sierraville, Weed, and Yreka.

High Prices, High Variability:
Beverly Hills, Blairsden-Graeagle, Boron, Coalinga, Downieville, King City, Needles, and Soledad.

Figure D-3
Scatter Plot of California Cities: May 2005



Source: CEC staff analysis of Oil Price Information Service (OPIS) data.

The outlying cities for May 2005 are categorized as follows:

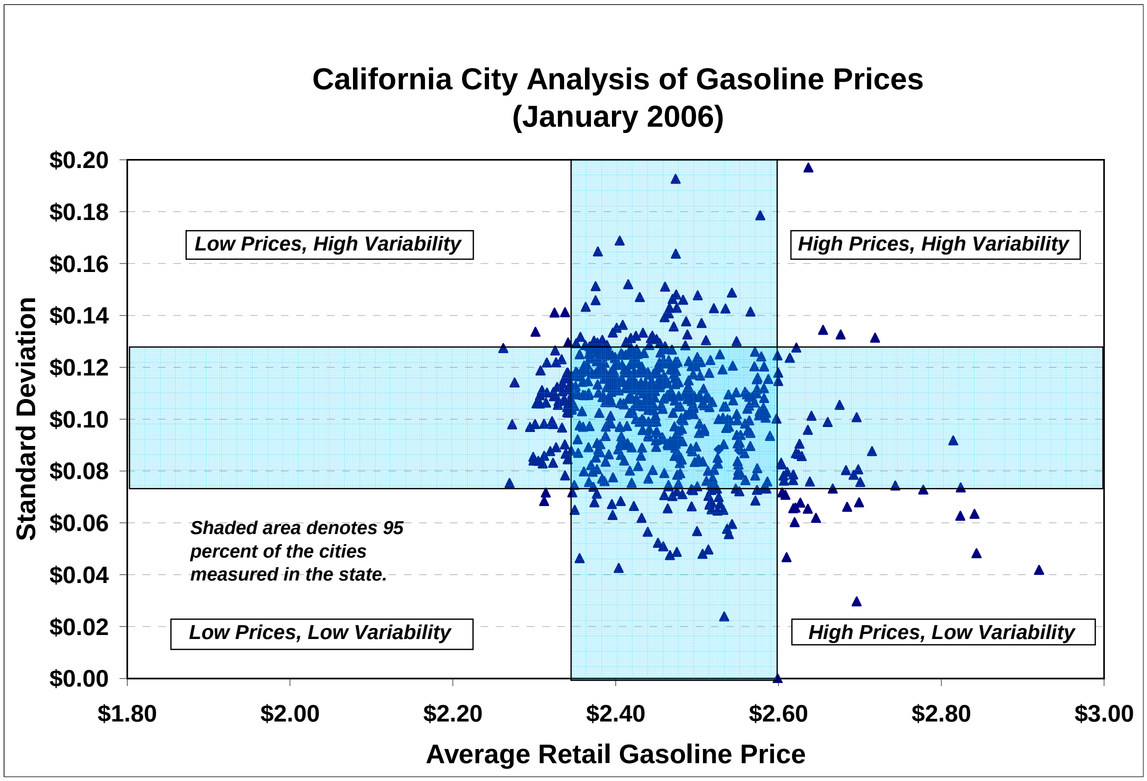
Low Prices, Low Variability:
Foresthill and Reseda.

Low Prices, High Variability:
Buttonwillow, Dixon, Gridley, Marysville, and Yuba City.

High Prices, Low Variability:
Baker, Blue Lake, Bodega Bay, Clearlake, Coronado, Downieville, Hornbrook, La Grange, Laytonville, Linden, Los Alamos, Lower Lake, Martell, Maxwell, Ocotillo, Pacific Palisades, Pine Valley, Point Reyes Station, Portola Valley, Trinidad, and Villa Park.

High Prices, High Variability:
Gualala, Ludlow, Mill Valley, San Bruno, San Francisco, and South San Francisco.

Figure D-4
Scatter Plot of California Cities: January 2006



Source: CEC staff analysis of Oil Price Information Service (OPIS) data.

The outlying cities for January 2006 are categorized as follows:

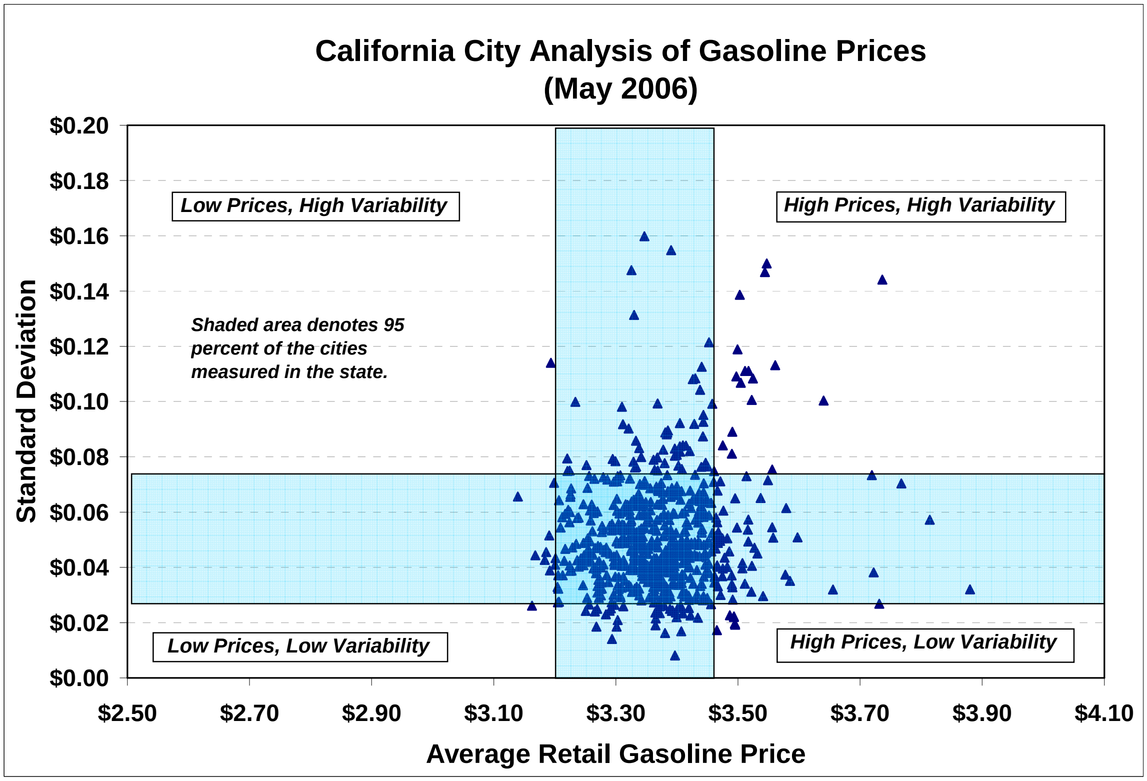
Low Prices, Low Variability:
Angwin and Antelope.

Low Prices, High Variability:
Concord, Fountain Valley, Novato, and Suisun City.

High Prices, Low Variability:
Baker, Bishop, Blue Lake, Fortuna, Kings Beach, Ludlow, Mammoth Lakes, Maxwell, McCloud, Olancha, Pine Grove, Pine Valley, Portola, Shaver Lake, Soda Springs, Soledad, Sutter Creek, and Willow Creek.

High Prices, High Variability:
Coalinga, Firebaugh, Joshua Tree, and South Lake Tahoe.

Figure D-5
Scatter Plot of California Cities: May 2006



Source: CEC staff analysis of Oil Price Information Service (OPIS) data.

The outlying cities for May 2006 are categorized as follows:

Low Prices, Low Variability:
Goshen.

Low Prices, High Variability:
Fairfield.

High Prices, Low Variability:
Los Alamos, Ludlow, Mount Shasta, Pearblossom, Pinon Hills, Shafter, and Villa Park.

High Prices, High Variability:
Arvin, Barstow, Beverly Hills, Bieber, Blythe, Boron, Catheys Valley, Clearlake Oaks, Crescent City, El Centro, Goleta, Lebec, Mariposa, Needles, Pala, and South Lake Tahoe.

Discussion

All cities that were not within the 95th percentile are considered outliers. In January 2005, a period of relatively low prices compared to the previous year, there was relatively low variability with respect to prices. There appears to be an almost equal number of outlying cities in each of the four quadrants.

By May 2005, retail prices rose from the observed range of $1.90 to $2.10 in January 2005 to the $2.40 to $2.80 range in May 2005. Fewer cities fell into the "low price" category. The variability of the average prices *increased* for the state as a whole. The majority of the high priced, low-variability stations were in geographically remote areas of the state.

Similar to the previous year, January 2006 exhibited cities with high prices and low volatility in more remote areas of the state such as King's Beach, Maxwell, and Soda Springs.

In May 2006, gasoline prices reached record levels across the state, ranging from $3.15 to almost $4.00 per gallon. All cities in the state at this time were closely clustered at about the average price. The overall variability of these prices was about half the value that was measured in January 2006.

Findings

A few general conclusions can be drawn from the scatter plots of the average price and standard deviation of retail prices of California cities.

Intuitively, a normal competitive environment - where all retailers are limited by what they can charge based on competition and market share - should exhibit a low standard deviation. Conversely, higher measures of standard deviation may indicate that retail prices are being affected by some external condition such as geography, lower volume throughput, and limited competition.

APPENDIX E

RECOMMENDED STATUTORY CHANGES

RECOMMENDED STATUTORY CHANGES

The Energy Commission suggests that the Legislature adopt the statutory changes below, in order to implement the recommendations discussed in Chapter 6. (Removed text is indicated by strikeout; new text is indicated by italics and underlining.)

1. *Financial Information*

Amend California Public Resources Code section 25354, subdivision (b)

> (b) Each major oil producer, refiner, marketer, oil transporter, and oil storer shall annually submit information to the commission in such form and extent as the commission prescribes pursuant to this section. *The commission may determine the form and extent necessary by order or by regulation.* The information shall be submitted within 30 days after the end of each reporting period, and shall including the following:
>
> *   *   *   *
>
> *(6) Each person required to report pursuant to this subdivision shall annually submit to the commission such financial information as the commission may determine necessary for the purpose of analyzing and reporting upon the profits, earnings and other financial conditions of the California petroleum industry, including, without limitation, financial information pertaining to exploration and production; transportation (whether by one or more of marine vessel, pipeline, rail or tanker truck); refining; marketing; trading; retail; and such other industry functions as the commission deems necessary and appropriate for purposes of this section. Except to the extent previously made public by the person supplying the information, the financial information obtained pursuant to this subdivision shall be held in confidence by the commission. Any report of the commission pursuant to this subdivision shall only include confidential financial information if the information is aggregated to the extent necessary to assure confidentiality, if public disclosure of the specific information would result in unfair competitive disadvantage to the person supplying the information.*

2. Costs Reporting

Amend California Public Resources Code section 25354, subdivisions (h) and (i).

(h) Each refiner shall submit to the commission within 30 days after the end of each monthly reporting period, all of the following information in such form and extent as the commission prescribes:

(1) Monthly ~~California~~ weighted average *cost,* prices and sales volumes of finished leaded regular, unleaded regular, and premium motor gasoline sold *within California* through company-operated retail outlets, to other end-users, and to wholesale customers.

(2) Monthly ~~California~~ weighted average *cost,* prices and sales volumes for residential sales, commercial and institutional sales, industrial sales, sales through company-operated retail outlets, sales to other end-users, and wholesale sales of No. 2 diesel fuel and No. 2 fuel oil*, sold in California*.

(3) Monthly ~~California~~ weighted average *cost,* prices and sales volumes for retail sales and wholesale sales of No. 1 distillate, kerosene, finished aviation gasoline, kerosene-type jet fuel, No. 4 fuel oil, residual fuel oil with 1 percent or less sulfur, residual fuel oil with greater than 1 percent sulfur. And consumer grade propane, *sold in California*.

(i)(1) Beginning the first week after the effective date of the act that ~~added~~ *amends* this subdivision (i), and each week thereafter an oil refiner, oil producer, petroleum product transporter, petroleum product marketer, petroleum product pipeline operator, *petroleum trader*, and terminal operator, as designated by the commission, shall submit a report in the form and extent as the commission prescribes pursuant to this section. The commission may determine the form and extent necessary by order or by regulation.

(2) A report may include any of the following information:

(A) Receipts, *weighted average cost*, and inventory levels of crude oil and petroleum products at each refinery and terminal location, *within and without California*.

(B) Amount, *weighted average cost, and weighted average sales price, by category,* of gasoline, diesel, jet fuel, blending components, and other petroleum products imported *into,* and exported *from, California*.

(C) Amount, *weighted average cost of transportation, by category,* of gasoline, diesel, jet fuel, blending components, and other petroleum products transported intrastate by marine vessel.

(D) Amount *and weighted average cost* of crude oil imported *into California, and imported into the United States, excluding California,* including information identifying the source of the crude oil.

(E) The regional average of invoiced retailer buying price*, by product, and associated regional average cost of each product sold to such retailer*. This subparagraph does not either preclude or augment the current authority of the commission to collect additional data under subdivision (f).

(F) Daily spot market trading activity, including prices, quantities, delivery dates, identity of trading partners, and such other information as the commission deems necessary and appropriate for the purposes of this chapter.

(3) This subdivision is intended to clarify the commission's existing authority under subdivision (f) to collect specific information. This subdivision does not either preclude or augment the existing authority of the commission to collect information.

3. *Spot Market Trading Activity*

Amend California Public Resources Code section 25354, subdivisions (i)(1) and (i)(2)(F), as shown above.

Marine Terminal Operations

Amend Cal. Public Resources Code section 25354 by adding a new subdivision (j).

(j) The commission may, by rule or order, collect data from owners and operators of marine petroleum terminals, owners and operators of marine vessels shipping petroleum products, the Southern California Marine Exchange and its successors, and from the Marine Exchange of the San Francisco Bay Region and its successors, such information as it deems necessary and appropriate to analyze and report upon actual and potential congestion at marine petroleum terminal facilities within the state. Each person required to report pursuant to this subdivision shall provide this information at such interval and in such format as determined by the commission. Except to the extent previously made public by the person supplying the information, the information obtained pursuant to this subdivision shall be held in confidence by the commission. Any report of the commission pursuant to this subdivision shall only include confidential marine petroleum terminal information if the information is aggregated to the extent necessary to assure confidentiality, if public disclosure of the specific information would result in unfair competitive disadvantage to the person supplying the information, or would infringe upon proprietary information or divulge information constituting a trade secret.

4. *Confidentiality – Information Sharing with the Attorney General*

Amend California Public Resources Code section 25364, subdivisions (g).

> (g) Notwithstanding any other provision of law, the commission may disclose confidential information received pursuant to*:* ~~subdivision (a) of Section 25304 or Section 25354 to the State Air Resources Board if the state board agrees to keep the information confidential. With respect to the information it receives , the state board shall be subject to all pertinent provisions of this section.~~
>
> *(1) Subdivision (a) of Section 25304 or Section 25354 to the State Air Resources Board if the state board agrees to keep the information confidential. With respect to the information it receives, the state board shall be subject to all pertinent provisions of this section; and*
>
> *(2) Section 25354 to the California Attorney General if the Attorney General provides a written request for the information, in connection with an ongoing investigation. With respect to the information the Attorney General receives, the Attorney General shall be subject to all pertinent provisions of Cal. Government Codes sections 11180, et seq. pertaining to confidentially of investigatory records.*

5. *Contact Information for Retail Service Stations*

Amend California Civil Code section 1798.69.

> 1798.69. Release of names and addresses; State Board of Equalization
>
> (a) Except as provided in subdivision (b), the State Board of Equalization may not release the names and addresses of individuals who are registered with, or are holding licenses or permits issued by, the State Board of Equalization except to the extent necessary to verify resale certificates or to administer the tax and fee provisions of the Revenue and Taxation Code.
>
> (b) Nothing in this section shall*:*
>
> *(i)* Prohibit the release by the State Board of Equalization to, or limit the use by, any federal or state agency, or local government, of any data collected by the board that is otherwise authorized by law~~.~~*; and*
>
> *(ii) Prohibit the release by the State Board of Equalization to the State Energy Resources Conservation and Development Commission of any data collected by the board that identifies by name, address, or telephone number, business entities engaged in the retail sale within the state of gasoline or diesel fuel.*

APPENDIX F

KEY TRANSPORTATION ENERGY RECOMMENDATIONS

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Bioenergy Action Plan for California (July 2006)

The Bioenergy Action Plan is designed to achieve a number of broad state policy objectives such as “maximize the contributions of bioenergy toward achieving the state’s petroleum reduction, climate change, renewable energy, and environmental goals.”

Biomass Production and Use Targets

In Executive Order S-06-06, Governor Schwarzenegger established the following targets to increase the production and use of bioenergy, including ethanol and biodiesel fuels made from renewable resources:

- Regarding biofuels, the state shall produce a minimum of 20 percent of its biofuels within California by 2010, 40 percent by 2020, and 75 percent by 2050.

Multi-Agency Collaborations

As directed by the Governor, the Energy Commission will coordinate with the Working Group on the use of state funds and on securing federal funding that support strategic research, development, and demonstration (RD&D) projects, including efforts to:

- Prove the commercial readiness of biofuels production and advanced biomass conversion technologies including cellulosic feed stocks derived from forestry, agriculture, and urban wastes by 2010.

California Energy Commission Responsibilities

- Report on progress in implementing the state policy objectives, biomass production and use targets, and actions detailed in this Plan in the biennial Integrated Energy Policy Report, as directed by the Governor.

- Complete a comprehensive “road map” to guide future research, development, and demonstration activities through the California Biomass Collaborative by September 30, 2006. Among other items, the Energy

Commission will work with the Hydrogen Highway team to ensure that this road map evaluates the potential for biofuels to provide a clean, renewable source of hydrogen.

- Prepare the State Alternative Fuels Plan by the June 30, 2007, Legislative deadline, with a progress report by December 31, 2006, that, among other things, will identify actions and incentives to increase the production and use of biofuels and to develop an extensive and convenient E-85 network in new and retrofitted service stations in California.

The California Air Resources Board Responsibilities

- Enable the most flexible possible use of biofuels through its Rulemaking to Update the Predictive Model and Specifications for Reformulated Gasoline, while preserving the full environmental benefits of California's Reformulated Gasoline Programs, as required by Health and Safety Code section 43013.1, by January 31, 2007.

- Complete the Rulemaking for presentation to the Board by January 31, 2007. As part of the rulemaking, reflect the emissions performance of current and future vehicle fleets and incorporate available data on the emissions impact of fuel properties.

- As data becomes available on the impacts of fuel specifications on the current and future vehicle fleets, review and update motor vehicle fuel specifications as appropriate. In reviewing the specifications, consider the emissions performance, fuel supply consequences, potential greenhouse gas reduction benefits, and cost issues surrounding ethanol blends, particularly E6, E10, and E85, for gasoline by January 31, 2007, and for diesel by December 31, 2008.

- Consider adoption of fuel specifications for motor vehicle fuels, such as B2, B5, B20, and B100 by December 31, 2007.

- Evaluate the greenhouse gas reductions benefits of bio-fuels and biomass production and use, and report back to the Working Group on recommended options to encourage their use, in close cooperation with the other members of the Working Group, by June 30, 2007.

- Evaluate the suitability of using available regulatory levers to encourage the establishment of E-85 stations in California by June 30, 2007.

- Complete a peer-reviewed study of the emissions performance, costs, and benefits of using biofuels and biofuel blends, using a multi-media approach by July 31, 2008.

- Consider adoption of regulations by June 30, 2008, that require all gasoline powered vehicles sold in the state to meet the state's emission standards using gasoline blended with up to 10 percent ethanol and consider a requirement increasing the percentage of E85-compatible vehicles sold in the state.

- Consider adoption of regulations by June 30, 2008, requiring heavy-duty diesel engine manufacturers to warrantee heavy-duty diesel engines using California diesel and B2, B5, and B20 meeting the California specifications indicated above.

The State Department of General Services Responsibilities

Develop an annual statewide vehicle asset plan by December 31, 2006, that, through the Statewide Equipment Council that:

a. Includes flexible fuel vehicles in the state's vehicle procurement program.

b. Requires state vehicle contracts to be based on a Life Cycle Cost Analysis methodology.

c. Requires state agencies (for light-duty, non-public safety applications, and other applications as practical) to purchase flexible fuel vehicles capable of operating on renewable and alternative fuels, increasing to 50 percent of total new vehicles purchased by 2010.

Legislative Options for Possible Action

The Working Group identified two topics for possible action during the 2006 legislative session:

- Amend existing law to revise existing technology definitions and establish new ones to enable use of biomass residues through both combustion and non-combustion technologies.

- Amend existing law to provide incentives to local jurisdictions for energy production activities.

In addition, the Working Group identified potential topics for future legislation, but for which additional evaluation is needed before determining the suitability of a legislative remedy.

- Establish a California renewable fuels standard based on fuel content that could include a minimum average of 10 percent renewable content in gasoline and a 5 percent non-petroleum diesel fuel standard.

- Recommend a package of tax incentives to encourage use of biomass, biofuels, and other bio-based products.

2005 Integrated Energy Policy Report (November 2005)

As directed by the Governor, the Energy Commission has assumed the lead in developing a long-term transportation plan that will reduce gasoline and diesel use and increase alternative fuel use. This effort is a prelude to the alternative fuel plan for the state required by AB 1007 (Pavley), Chapter 371, and Statutes of 2005, due by June 30, 2007. The Energy Commission envisions that the alternative transportation fuel plan must bridge the gap between today's technologies and the transition to hydrogen fuels and vehicles called for in the Governor's Hydrogen Highway Network Blueprint Plan. California must pursue a diverse portfolio of fuels and advanced transportation technologies that address both current supply and demand problems and build a sustainable foundation for the future.

The Energy Commission adopted the following transportation recommendations to the Governor:

- The state should simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce emissions of air pollution and greenhouse gases.

- The state should implement a public goods charge to establish a secure, long-term source of funding for a comprehensive transportation program including broad-based funding for infrastructure, technology and fuels research, analytical support, and incentive programs.

- The state should continue to work closely with other states to pressure the federal government to double vehicle fuel efficiency standards and enact fleet procurement requirements that include super-efficient gasoline and diesel vehicles.

- The state should establish a non-petroleum diesel fuel standard so that all diesel fuel sold in California contains a minimum of 5 percent non-petroleum content that would include biodiesel, ethanol, and/or gas-to-liquid components.

- The state should establish a state renewable gasoline fuel standard so that the pool of all gasoline sold in California contains, on average, a minimum of 10 percent renewable content.

- The state should investigate how investor-owned utilities can help develop the equipment and infrastructure to fuel electric and natural gas vehicles.

- The state should, for its fleet of vehicles, establish a minimum fuel economy standard and a procurement requirement for alternative fuels and vehicles, and examine the merits of using re-refined and synthetic oils.