California Energy Commission

**FINAL STAFF REPORT**

# Transportation Fuel Supply Outlook, 2017

**California Energy Commission**

Edmund G. Brown Jr., Governor

**September 2017 | CEC-200-2017-008-SF**

# California Energy Commission

Gordon Schremp
Ryan Eggers
**Primary Authors**

Ryan Eggers
**Project Manager**

Marc Pryor
**Acting Office Manager**
**SUPPLY ANALYSIS OFFICE**

Sylvia Bender
**Deputy Director**
**ENERGY ASSESSMENTS DIVISION**

Robert P. Oglesby
**Executive Director**

# ACKNOWLEDGEMENTS

| | |
|---|---|
| Narayani Balakrishnan | pipeline movement analysis |
| Susan Ejlalmaneshan | marine import/export analysis |
| Julio Gutierrez | refinery analysis |
| Foua Moua | retail fuel sales analysis |
| Alexander Wong | PIIRA data consultation |
| Gary Yowell | alternative fuel consumption analysis |
| Barbara Crume | formatting/editing |
| Harinder Kaur | formatting/editing |

# ABSTRACT

California Public Resources Code Section 25301 requires the California Energy Commission to prepare an *Integrated Energy Policy Report* every two years that includes assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The Energy Commission uses these assessments and forecasts to provide an analytic foundation for developing energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety.

This report looks at information collected by the Energy Commission through its Petroleum Industry Information Reporting Act regulations for analyzing trends in liquid fuel production, storage, and distribution. Energy Commission staff developed new metrics using aggregated data collected by this regulation to help inform the California public on the operations of liquid transportation fuels supply chains. In addition, staff analyzed several other data sources to provide a more comprehensive discussion of California's liquid transportation fuel issues.

Report topics include:

- California, United States, and world crude oil production.
- Refinery operations and crude oil utilization.
- Production of liquid transportation fuels.
- Import and export volumes of liquid transportation fuels for Northern and Southern California.
- Liquid biofuel production and feedstock utilization.
- Industry regulatory changes and issues.

**Keywords:** Price, transportation, gasoline, petroleum, diesel, liquid, alternative gaseous fuels

Schremp, Gordon, Ryan Eggers. 2017. *Transportation Fuel Outlook, 2017*. California Energy Commission. Publication Number: CEC-200-2017-008-S**F**.

# TABLE OF CONTENTS

**Page**

# LIST OF FIGURES

**Page**

# LIST OF TABLES

# EXECUTIVE SUMMARY

This report describes the trends and relevant issues faced by California's liquid transportation fuel market and its supply infrastructure. Using information from its Petroleum Industry Information Reporting Act data collection regulations, as well as from public and proprietary sources, staff details the flows of the liquid fuels network and the volumes of the product that is being moved, produced, and consumed in California. The following report has been organized into five chapters with selected findings listed by chapter. Chapter 1 is an introduction to transportation fuels and outlines major topics to be discussed in the report.

**Chapter 2—Crude Oil Production**

- Crude oil production in California continues the decline from the 1985 high of 424 million barrels to 194 million barrels in 2016. In response to this reduced production, California continues to import more crude oil, which totaled 328.5 million barrels in 2016 and represented 54.5 percent of all crude oil inputs to refineries in that year.
- United States crude oil production has increased significantly since 2008 due to increased tight oil (shale) production. In April 2015, the United States reached a production level of 9.6 million barrels per day (BPD), which was a 30-year high in crude oil production. This was less than a half-million BPD less than the United States all-time high of 10 million BPD in November 1970.
- Crude oil transported via rail car in California has declined significantly since the high in late 2013. In 2015 and 2016, crude-by-rail has averaged less than 200,000 barrels per month due to poor economics and availability of less expensive crude oils. In 2016, crude-by-rail provided oil from Wyoming and New Mexico only.

**Chapter 3—California's Transportation Fuel Supply Network**

- California refinery operations have remained stable with only major unplanned refinery outages upsetting the market. In 2016, 42.9 percent of California refinery production was California Air Resources Board (CARB) compliant gasoline (all grades), 13.4 percent CARB-compliant diesel, and 13.6 percent jet fuel. Non-CARB-compliant gasoline (all grades) and diesel, along with other petroleum products, formed the remaining 30.1 percent of production.
- California consumption of finished gasoline has increased for four consecutive years (2013–2016) and in 2016 is only about 400 million gallons below its previous consumption high of 15.9 billion gallons (2004). While finished gasoline has increased, consumption of California reformulated gasoline blendstock for oxygenate blending in 2016 remains roughly 1 billion gallons below its 2003 consumption high of 15 billion gallons, due to increased use of ethanol.

- Increased use of biodiesel and renewable diesel in California has helped slow increases in petroleum-based diesel consumption. More than 400 million gallons of biodiesel and renewable diesel was consumed in 2016, a 55-fold increase in consumption since 2010.
- California's petroleum infrastructure remains isolated from other Petroleum Administration for Defense Districts, with marine transport of products being the only large-scale connection to the rest of the nation. Since the 2003 phaseout of methyl tertiary butyl ether, blending components for finished gasoline are the main foreign import into California, as opposed to finished gasoline. Foreign imports of gasoline components into California have been sourced from 62 countries over the last 30 years.
- Both Northern and Southern California import and export gasoline and diesel products continuously. From 2007 to 2016, Northern California always been a net exporter of gasoline and diesel product with the exception of one month in 2015 for gasoline and two months in 2007 for diesel. Southern California has switched between being a net importer to a net exporter of gasoline throughout the 2007 to 2016 period. For diesel, Southern California was consistently a net exporter of product.
- In response to the Torrance refinery outage in 2015–2016, Southern California became a large net importer of gasoline product. From trough to peak, this shift equated to roughly 3 million barrels in additional product flowing into the area, which would account for roughly 10 percent of California's monthly gasoline consumption. With this shift in imports, California's refiner acquisition cost of crude oil to pretax retail margin increased to nearly $2.00 in August 2015.

## Chapter 4—Renewable and Alternative Fuels

- Use of renewable and other alternative fuels in the United States and California is expected to continue growing. This expected growth is primarily a result of federal and state regulations mandating ever-increasing levels of renewable content in gasoline and diesel fuel, carbon reduction rules, and incentives for increasing alternative fuel consumption.
- Liquid biofuels (ethanol, biodiesel, and renewable diesel) are providing significant petroleum and greenhouse gas reductions. In 2016 these fuels provided more than 25 percent of California's petroleum reductions and 82 percent of the CARB Low Carbon Fuel Standard program greenhouse gas reductions.
- Ethanol has grown to 10 percent of the finished gasoline pool, displacing 1.1 billion gallons of gasoline. Of that ethanol consumption, 85.9 percent of California's ethanol is rail-imported and 11.9 percent produced in-state.
- In 2016, biodiesel and renewable diesel use grew to 412 million gallons, displacing 15.8 percent of diesel fuel. Biodiesel reached 4.75 percent of the state blend level, just 0.25 percentage points below the regulatory diesel-blend limit. Future biodiesel growth is limited unless the fuel is sold as a unique higher biodiesel blend.

- Ethanol and biodiesel will likely reach the maximum fuel blend or blend-wall limits in 2017. Consequently, future growth in ethanol and biodiesel will be significantly slower. Renewable diesel growth is not limited and is expected to continue to grow.

### Chapter 5—Transportation Fuel Price Analysis

- Crude oil prices in California and the rest of the world appear driven largely by world consumption and production imbalances, as well as changes in the purchasing power of the U.S. dollar in the international market. Periods of prolonged consumption outpacing production have corresponded with crude oil price increases and vice versa. Periods with continual weakening of the dollar, with consumption outpacing production, have shown to accelerate crude oil price increases and vice versa.
- Gasoline refiner margins (Refiner Acquisition Cost) to rack price differential have increased in 2015 and 2016, yet are still below 2006 and 2007 highs. Since 2011, retail margins (rack to pretax retail price differential) have increased noticeably to above $0.40. Diesel refiner margins have averaged between $0.50 to $0.60 since 2011 but, like gasoline, the diesel retailer margin has increased steadily to roughly $0.50 in 2016.
- E85 (generic term for fuel anywhere from 51-83 percent ethanol), biodiesel, renewable diesel, and transportation-use propane prices have tracked petroleum-based gasoline and diesel prices since 2000. Transportation-use compressed natural gas, liquefied natural gas, and electricity prices have not.

# CHAPTER 1: Introduction

This report describes the trends and relevant issues faced by California's liquid transportation fuel market and its supply infrastructure. The purpose is to provide context to the information that the California Energy Commission collects through its Petroleum Industry Information Reporting Act (PIIRA) data collection regulations, as well as from public and proprietary sources. Much of the information included in this report is provided on the Energy Commission website at http://www.energy.ca.gov/ and can be found in the *Petroleum Data, Facts, and Statistic* page of that site (http://www.energy.ca.gov/almanac/petroleum_data/). Final statistics and data tables of the information are made public in aggregated formats to protect the confidentiality of the reporting entities, while still providing the California public and policy makers with the information needed to make informed decisions on liquid transportation fuels.

The Energy Commission has a 25-year history of publishing refinery production and inventory numbers for public use. Today, the Energy Commission's Supply Analysis Office staff issues *Weekly-Fuels-Watch*, which is an often-cited resource used by the California spot fuel markets. This report informs market participant about California's overall supply situation as well as the supply situations in the state's northern and southern regions. While publishing *Weekly Fuels Watch* and other key liquid fuel supply information has been helpful to those engaged in the markets, the public would be better served through analysis providing context and descriptions of market trends. With that purpose, staff has developed this report to not only share additional information the Energy Commission collects, but to analyze the liquid transportation fuel system as a whole. It is staff's intention that this report will evolve to include new, publicly desired analyses, as well as improved understanding of the data and the information derived from the data.

The report is organized into four topical chapters, each describing a different component of the liquid transportation fuel market.

Chapter 2 addresses crude oil issues relevant to California refineries and the data used to analyze it. In 2016, gasoline and diesel consumption within California totaled roughly 19 billion gallons of fuel combined, most of which was made from crude oil. California's extraction of crude oil from in-state wells provides only 34 percent of the state's needs. The rest is imported, either from other states or countries. The need to purchase crude oil in both the national and global markets led staff to analyze recent global crude oil trends, and to provide the geographic context concerning imports. In addition, the report describes current United States production of crude oil and how it will influence California's transportation fuel supply.

Chapter 3 focuses on the production, shipping, and subsequent retailing of finished transportation fuels, such as gasoline and diesel, in the California market. California has 15 fuel-producing refineries within its borders, and Chapter 3 provides information on the associated locations and statistics on the products these refineries make, beyond those provided in the

*Weekly Fuels Watch*.[1] Some refineries have been in operation for more than 100 years. The current roster provides nearly all of the gasoline, diesel, and jet fuel California needs, while providing substantial fuel to the Nevada and Arizona markets.

Even with these substantial production volumes, California's northern and southern refinery hubs are active import and export markets of transportation fuels, with finished products and blending components entering and exiting the area continuously. Exploring this dynamic in detail, staff analyzed both gross and net finished petroleum product flows for each refinery hub. The analysis shows a complex connectivity between California's neighboring states and the rest of the world.

California's roughly 10,000 retail fueling stations sell all of this fuel for end-use consumption. Using information from the Energy Commission's CEC-A15 *Annual Retail Fuel Outlet Report*,[2] staff analyzes the locations and types of stations retailing transportation fuel, as well as trends retail marketing. For instance, close attention is paid to the dispensing activities of "hypermart" retailers, such as Costco, Sam's Club, and Safeway.

Chapter 4 discusses the use of alternative and renewable liquid transportation fuels. California is transitioning to a diverse portfolio of transportation fuels including gaseous fuels (such as hydrogen and compressed natural gas), electricity, and alternative liquid fuels (ethanol, biodiesel, and renewable diesel). All these fuels are expected to play an important part in California's future transportation fuel mix, but the PIIRA data used in this report best inform liquid fuel consumption trends.

Supply issues for the United States as a whole are presented, followed by the results of staff's analysis of the profitability of these producers. Because many of the products used to make these fuels have other uses, fuel producers constantly evaluate the economics of moving product to and from fuel production based on price signals within those markets.

Chapter 5 provides a detailed look into liquid and other transportation fuel pricing trends in California and the forces that move prices up and down. Relationships identified in the previous chapters are expanded upon and used to illustrate how price responds to changes in these determinant forces. For liquid transportation fuels, many of the changes in price are a result of world crude oil supply-and-demand fundamentals. Staff first analyzes the trends in both the production of crude oil and the demand for that product on a world scale to later produce transportation fuel price cases. These cases will be used in another Energy Commission document, the *Transportation Energy Demand Forecast*.

Staff invites feedback and comments on this report and material contained within it. Comments can be provided to the Energy Commission's *2017 Integrated Energy Policy Report* (*IEPR*) docket that can be accessed at http://www.energy.ca.gov/2017_energypolicy/index.html or mailed and addressed to:

---

1 California Energy Commission Weekly-Fuels-Watch can be found at http://www.energy.ca.gov/almanac/petroleum_data/fuels_watch/.

2 *Annual Retail Fuel Outlet Report* results can also be found on the Energy Commission website at http://www.energy.ca.gov/almanac/transportation_data/gasoline/piira_retail_survey.html.

California Energy Commission

Dockets Office, MS-4

Re: Docket No. 17-IEPR-05

1516 Ninth Street

Sacramento, CA 95814-5512

## Hurricane Harvey

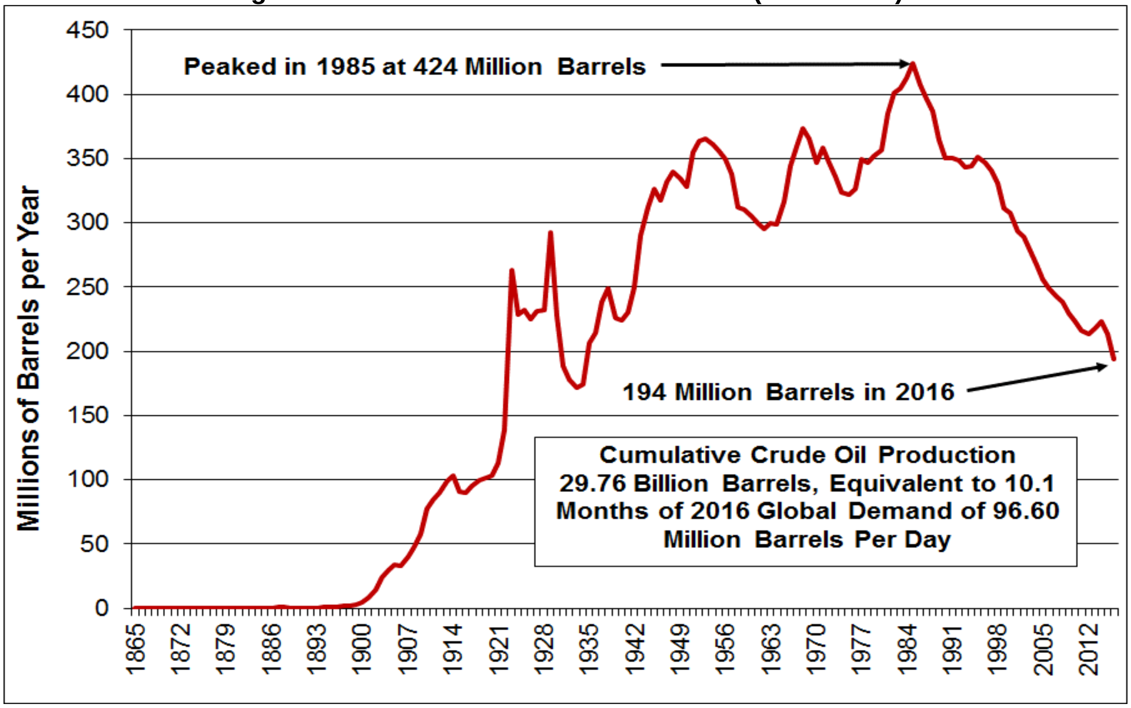
The publication of this report occurred just as the passage of Hurricane Harvey into Texas and Louisiana beginning on August 25th yielded the greatest amount of rainfall in history for the continental United States. Numerous refineries in the US Gulf Coast either were shut down as a safety precaution in advance of the hurricane's initial landfall or afterward due to excessive flooding, lack of crude oil access, or lack of ability to send fuel out through the normal pipeline and marine distribution infrastructure systems. Although California does not normally receive gasoline and diesel fuel supplies from refineries operating along the US Gulf Coast, this type of event can still significantly impact fuel prices in California since fuel prices are influenced by changes in the gasoline and diesel fuel futures contract markets. The relationship between local prices and New York Mercantile Exchange fuel contract activity allows sellers and buyers to hedge their business risk. This means that geopolitical and natural disaster events that can affect the price of gasoline futures contracts will result in wholesale and retail prices increasing in California and other parts of the United States. At the time of this publication the full magnitude and duration of outages for the refineries and pipeline distribution systems such as Colonial and Explorer Pipelines has yet to be realized. It is likely that the national transportation fuels markets will require at least two to four weeks to rebalance and resume more normal operations after allowing the full effects of the supply impacts and inevitable associated retail fuel price spikes to peak and then subside.

# CHAPTER 2:
# Crude Oil Production

California crude oil production has experienced persistent decline since 1985. Brief rebounds occurred in 2013 and 2014 when prices remained near $100 per barrel. The collapse of global crude oil prices that began during the summer of 2014 brought about a resumption of declining output, such that 2016 volume dropped below 200 million barrels for the first time since 1934.

California crude oil production began in the early 1860s with "production" obtained from horizontal shafts dug into the sides of hills that contained oil seeps.[3] Since then, technological advances in crude oil exploration and production have enabled companies to obtain crude oil from deeper reservoirs and extract nearly tar-like oil using thermally enhanced oil recovery, also known as *steam injection*. Most of California's crude oil-producing fields are mature, such as those in Kern County, and have been producing oil for more than 100 years. Over time, the drilling and extraction of crude oil result in diminished output from wells. As **Figure 1** illustrates, the production of California crude oil has peaked and has been declining for the majority of the years between 1985 and 2016. The consequence of the long-term declining trend is a growing shift to alternative sources of crude oil primarily from foreign sources.

**Figure 1: California Crude Oil Production (1876–2016)**



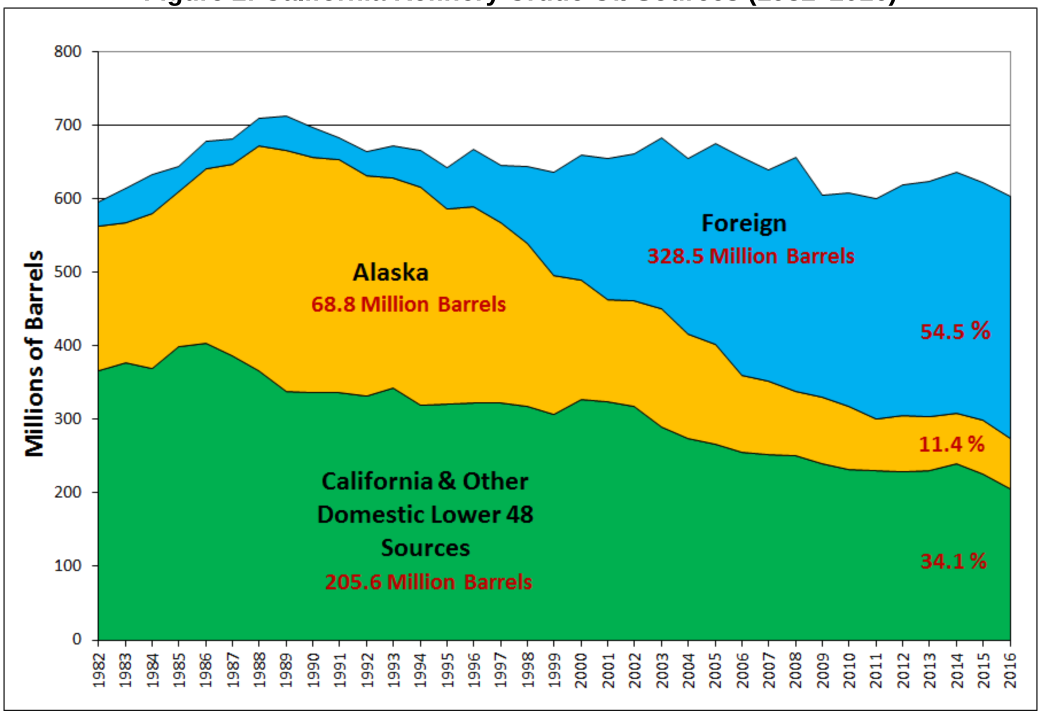

Sources: California Division of Oil, Gas, and Geothermal Resources and the Energy Commission, Energy Assessments Division, Supply Analysis Office

---

3 *Oil and Gas Production History in California*, Department of Conservation, Division of Oil, Gas, and Geothermal Resources, 1990. ftp://ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf.

Crude oil used by California refineries is sourced from in-state producers and imported from foreign and domestic sources. This crude oil is delivered to California primarily via marine vessels, in-state pipelines, and more recently via rail tanker cars. There are no crude oil pipelines that deliver crude oil to California refineries from outside the state. **Figure 2** illustrates how sources of crude oil to California refineries have shifted to becoming more dependent on foreign sources as supplies from Alaska and California have declined.[4] During 2016, California refiners received a total of 602.9 million barrels of crude oil for an average of 1.6 million barrels per day (BPD). About 54 percent came from foreign sources, 34 percent came from California and other domestic lower-48 state sources, and about 11 percent was from Alaska. All the crude oil from Alaska was delivered via marine tanker, as was the vast majority of foreign crude oil. A smaller portion (0.7 percent) of the domestic (California plus lower-48 state) crude oil was imported by marine vessel.[5]

**Figure 2: California Refinery Crude Oil Sources (1982–2016)**




Source: PIIRA.

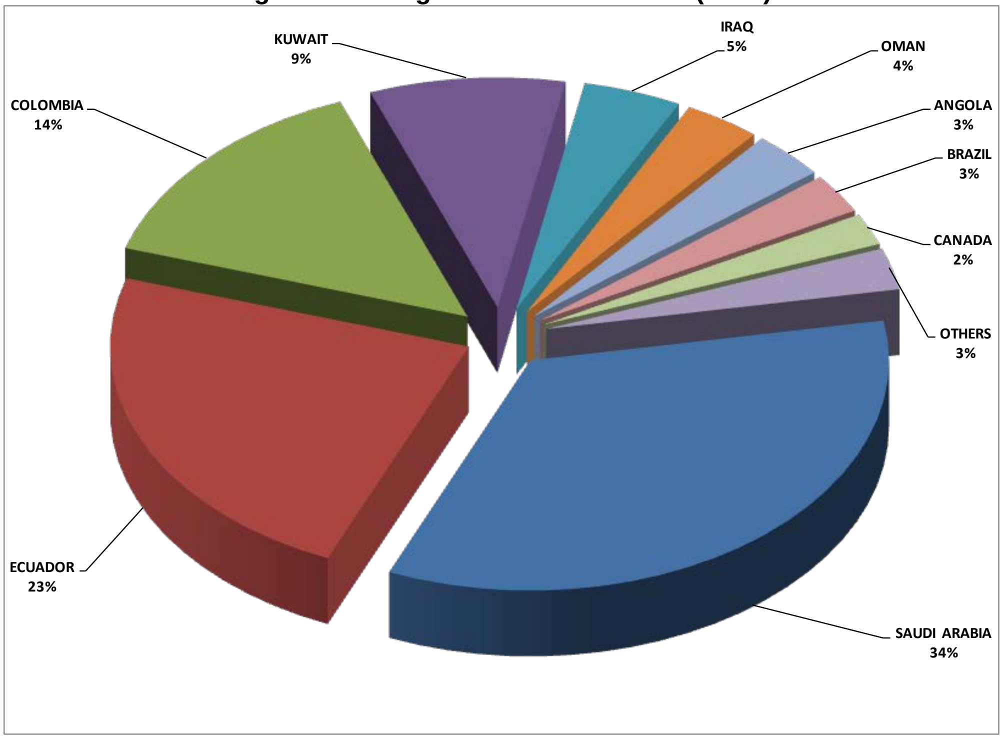
Crude oil imports from foreign sources are obtained from diverse countries. During 2016, Saudi Arabia was the largest source of foreign crude oil imports with 34 percent of total, followed by

4 California Energy Commission. This chart and detailed monthly data can be found at http://www.energy.ca.gov/almanac/petroleum_data/statistics/crude_oil_receipts.html.

5 A total of 1.638 million barrels of crude oil were imported by marine vessel from states other than Alaska during 2014; 92.5 percent of that volume originated in North Dakota, while the remainder originated from Utah. These volumes were initially transported by rail tank car to facilities in the Pacific Northwest before being transferred to marine vessels for shipment to California.

Ecuador (23 percent) and Columbia (14 percent). **Figure 3** depicts the top nine source countries' share of foreign crude oil imports.[6]

**Figure 3: Foreign Crude Oil Sources (2016)**




Source: U.S. EIA, Company-Level Imports.

## United States Crude Oil Extraction Developments

Although crude oil production is on the decline in California, that is not the case for the rest of the United States. Domestic crude oil production has rebounded dramatically in the United States due to the extensive use of horizontal drilling techniques and well treatment referred to as hydraulic fracturing.

*Hydraulic fracturing*, also known as "fracking or fracing," is a technique used by the petroleum industry to obtain crude oil and natural gas from geological formations that require additional effort to increase the volume of petroleum that can be removed from an existing field. These "tight oil and gas" formations require the rock to be fractured to enable the crude oil and natural gas to flow though the fissures to well bores and on to the surface. Hydraulic fracturing is not a new procedure and is estimated to have been used in more than one million wells worldwide. According to the California Division of Oil, Gas and Geothermal Resources (DOGGR), "In California, hydraulic fracturing has been used as a production stimulation method for more than 30 years with no reported damage to the environment."[7]

---

6 California Energy Commission. This figure and individual country totals are at http://www.energy.ca.gov/almanac/petroleum_data/statistics/2016_foreign_crude_sources.html.

7 DOGGR, Overview of Hydraulic Fracturing, http://www.conservation.ca.gov/dog/general_information/Pages/HydraulicFracturing.aspx.

At the June 25, 2014, *IEPR* workshop, Oil and Gas Supervisor Steven Bohlen from DOGGR explained how hydraulic fracturing in California differs from techniques used in the Marcellus Shale or other places. He noted that a substantial portion of California's wells "do require some kind of well stimulation in order to enhance recovery," but that the water used for well stimulations in California is much more restricted than in other parts of the country, by virtue of the vertical style of wells used here.[8] Additional progress has been made to improve the understanding of the impacts associated with hydraulic fracturing in California and access of information for the public.[9] Senate Bill 1281, (Pavley, Chapter 561) was signed into law by Governor Edmund G. Brown Jr. on September 25, 2014. This legislation requires "oil and gas operators to submit quarterly water reports detailing the source, quality, and treatment of all waters used for injection, disposal, and other oil and gas field activities."[10]

Continued improvement in technology, operating procedures, and understanding of subsurface petroleum deposit structures has allowed companies to deploy fracking in conjunction with horizontal drilling. This type of activity has been used in production in other parts of the United States, with success in tight oil formations in North Dakota (Bakken), southern Texas (Eagle Ford), and western Texas (Permian). **Figure 4** shows how quickly output from these shale oil basins has grown since January 2007. Although production from the Bakken and Eagle Ford basins peaked in 2015 and declined as global oil prices dropped, and drilling in these locations subsided, output from the Permian basin continued unabated. Permian production continues to rise even under a lower oil price environment because of lower drilling costs, higher yields, and better access to crude oil distribution infrastructure. Output from this oil field is now the second highest daily production in the world, trailing the Ghawar field in Saudi Arabia.

Production of oil in the United States stood at 8.8 million BPD during January 2017. **Figure 5** depicts the rebound of crude oil production in the United States, along with changes in output from key producing states. It is forecasted that production could continue increasing and eventually exceed the all-time record output of 10 million BPD achieved during November 1970.[11] The surge in domestic crude oil production is centered on the shale oil regions of the United States, such as the Permian and Eagle Ford formations in Texas, and Bakken formation in North Dakota.

---

8 June 25, 2014, *IEPR* workshop transcript, pgs. 65 – 66.

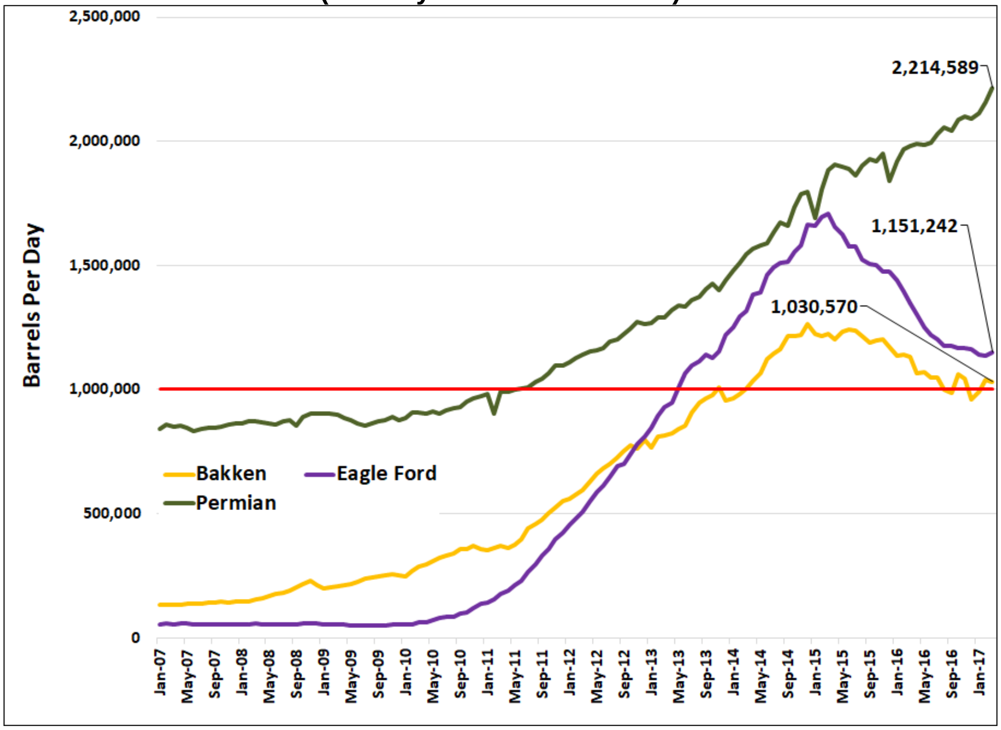
9 The following link to DOGGR's site provides extensive information related to hydraulic fracturing activities in California: http://www.conservation.ca.gov/dog/Pages/Index.aspx.

An overview of the hydraulic fracturing reporting requirements may be viewed at the following link: http://www.conservation.ca.gov/dog/general_information/Documents/121712NarrativeforHFregs.pdf.

10 The following link to DOGGR's site provides an overview of the new water-related reporting requirements for oil and gas producers in California: http://www.conservation.ca.gov/dog/SB%201281/Pages/Index.aspx.

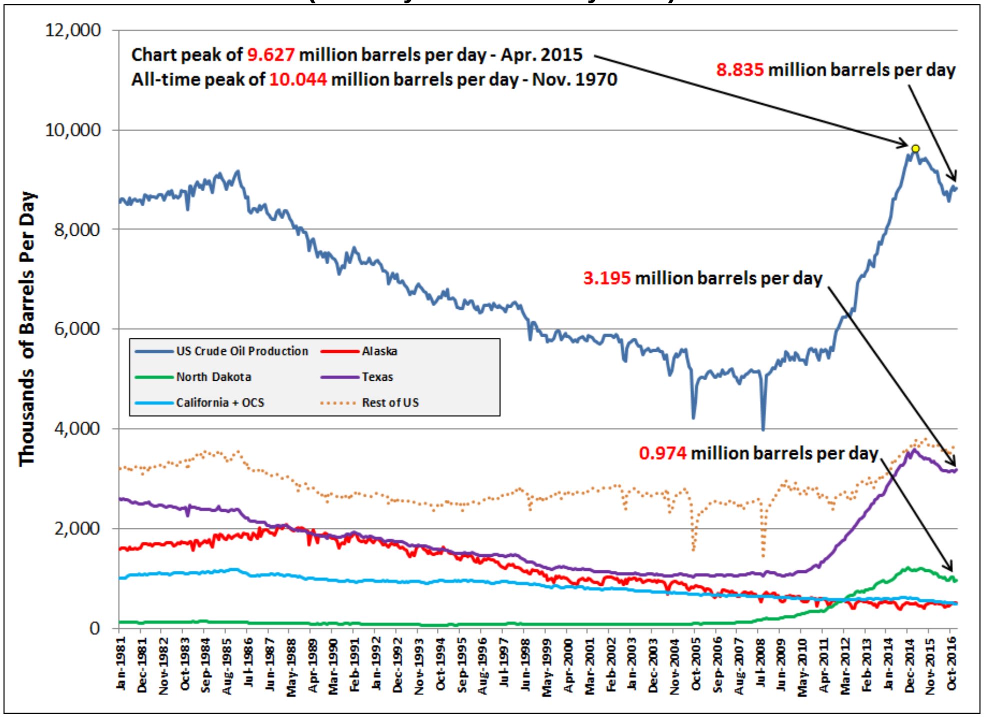
11 According to the U.S. EIA's latest update of its *Annual Energy Outlook* publication, crude oil production in the United States could reach 10.15 million BPD by 2022 under the "Reference Case" scenario. A link to the annual values and different scenarios is as follows: https://www.eia.gov/outlooks/aeo/excel/aeotab_14.xlsx.

**Figure 4: United States Oil Production by Shale Basin (January 2007 – March 2017)**




Source: U.S. EIA.

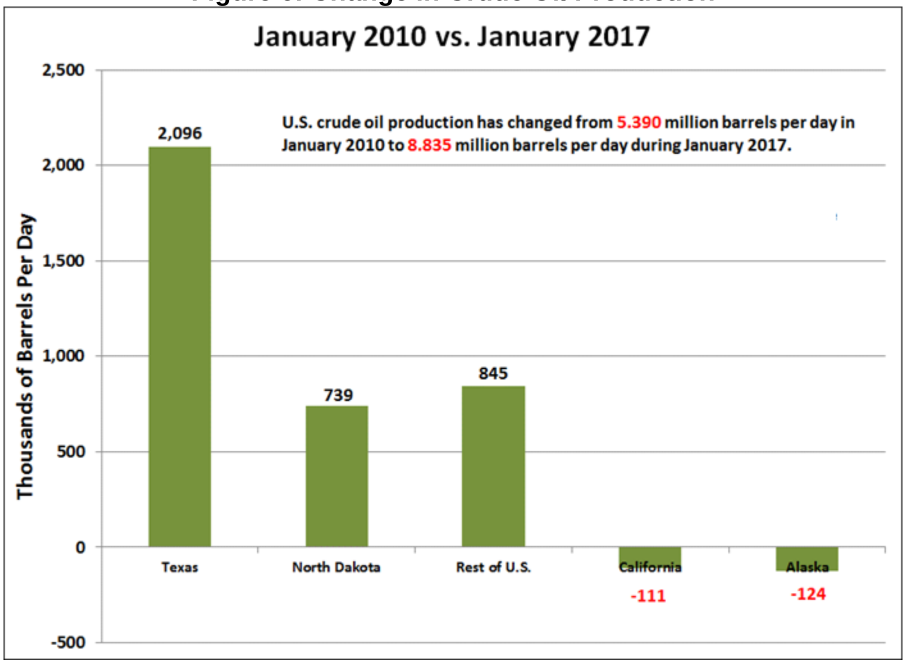
**Figure 5: United States Crude Oil Production (January 1981–January 2017)**




Source: U.S. EIA.

**Figure** 6 shows how much the oil production in those respective states has increased since January 2010 compared to California and Alaska. Texas and North Dakota account for 82.3 percent of the incremental crude oil production change between January 2010 and January 2017.

**Figure 6: Change in Crude Oil Production**

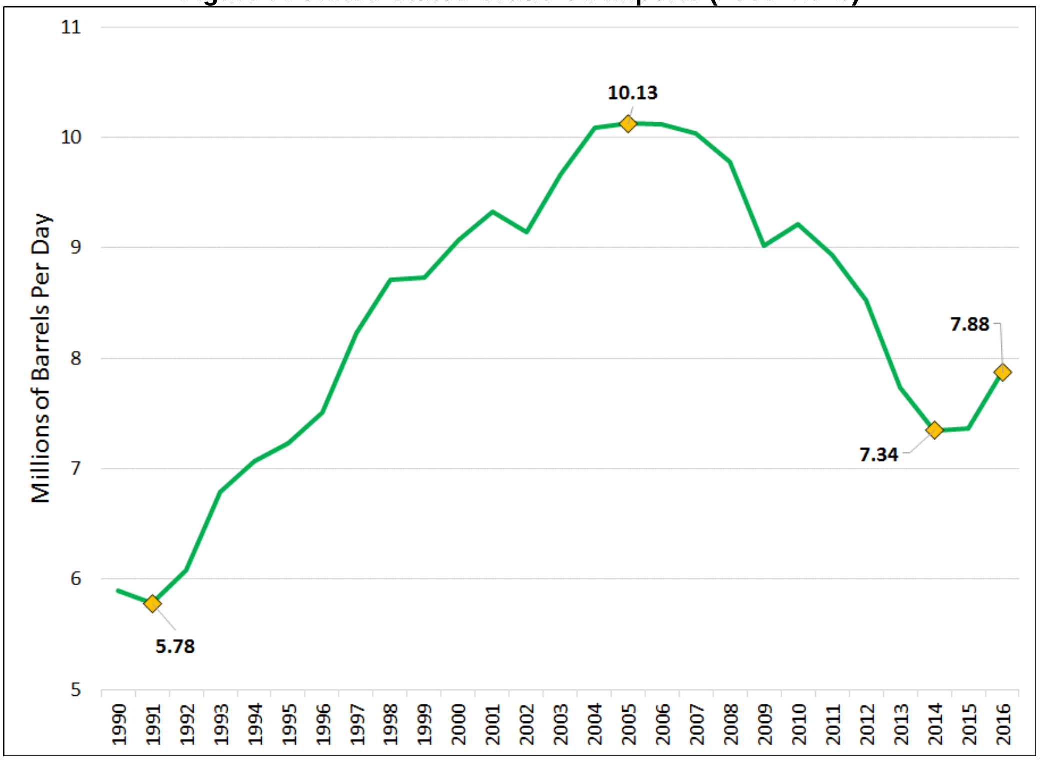



Source: U.S. EIA.

The tremendous rebound in domestic crude oil production has had a direct impact on imports into the United States by displacing the need for additional crude oil imports. **Figure 7** indicates crude oil imports to the United States increased by 75.1 percent between 1991 and the peak of 10.1 million BPD during 2005 before dropping to 7.3 million BPD by 2014 due to the rapid increase of domestic oil production from high crude oil prices stimulating development in shale oil production. However, the steady decline since 2005 has recently halted and rebounded to 7.8 million BPD for 2016, an increase of 7.3 percent.

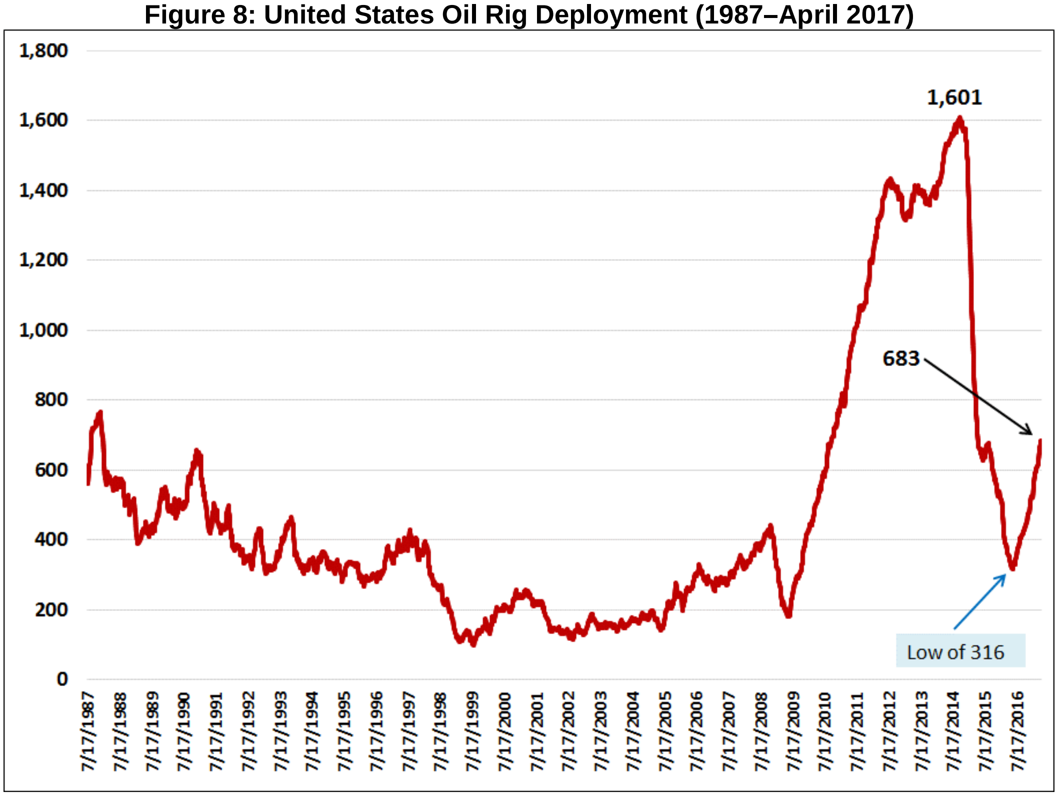
By 2015, a growing glut in global crude oil supplies placed downward pressure on crude oil prices, which discouraged drilling in the United States. **Figure 8** shows that the number of rigs deployed to drill for oil in the United States plummeted by 80.4 percent, from a peak of 1,601 on October 10, 2014, to a low of 316 on May 27, 2016. The reduction of drilling helped reverse the growth of domestic oil production in early 2016. Drilling has since rebounded by 116 percent as higher crude oil prices and lower operating costs enticed drilling companies to resume activity, especially in the Permian Basin.

**Figure 7: United States Crude Oil Imports (1990–2016)**




Source: U.S. EIA.

**Figure 8: United States Oil Rig Deployment (1987–April 2017)**

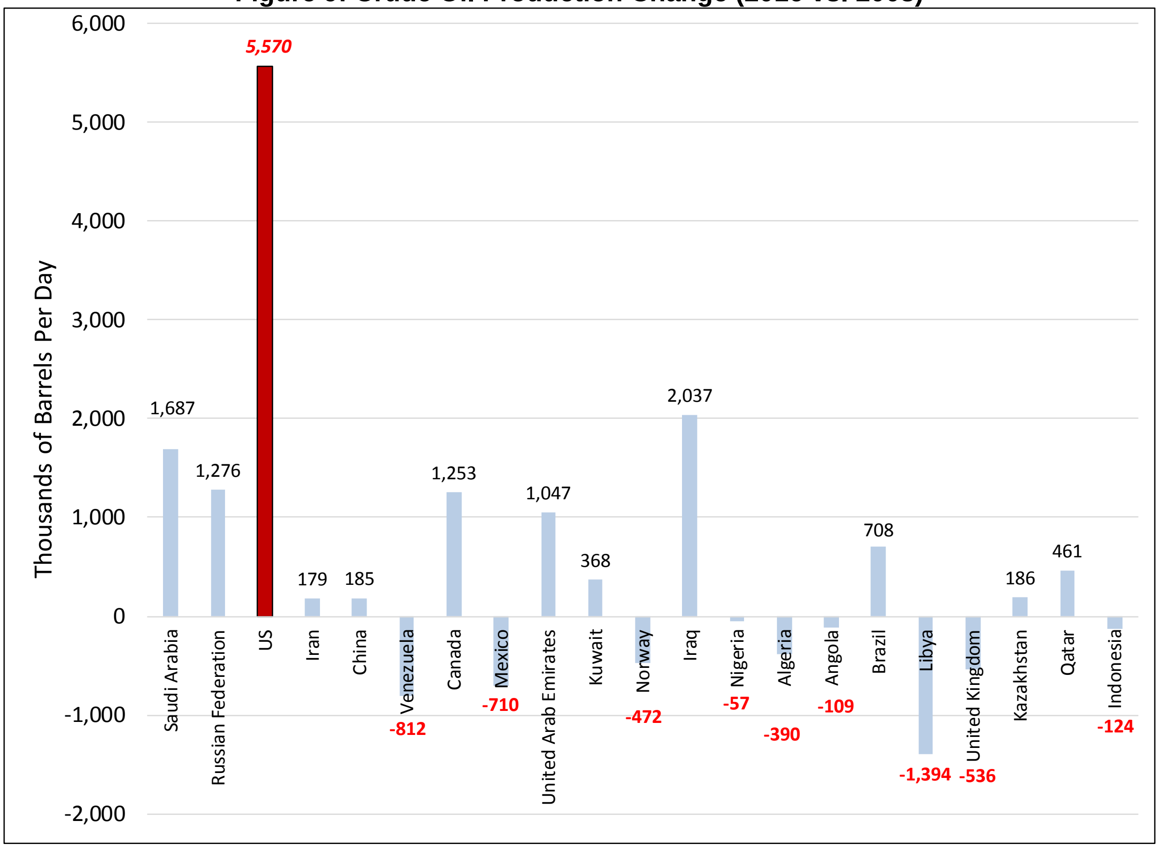



Source: Baker Hughes data—through April 13, 2017.

## Global Crude Oil Production Trends

In contrast to the crude oil production reversal upward in the United States, the trend in several other oil-producing countries is the opposite. During 2008, 21 countries produced at least one million BPD of crude oil, with the United States (6.8 million BPD) ranking third behind Saudi Arabia (10.7 million BPD) and Russia (9.95 million BPD).[12] By 2016, nearly half of those countries experienced declining oil production (**Figure 9**).

**Figure 9: Crude Oil Production Change (2016 vs. 2008)**



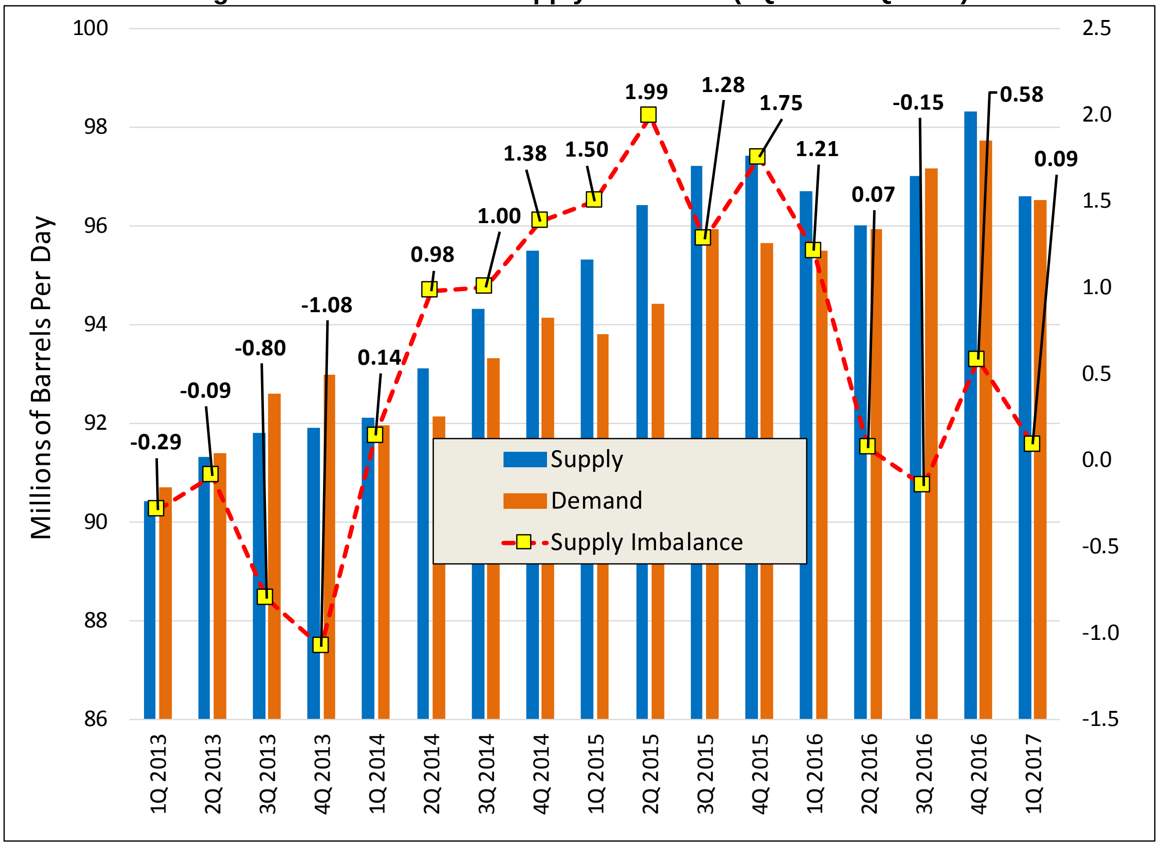

Sources: 2016 BP Statistical Review and Energy Commission analysis.

The surge in crude oil production from the United States coupled with the initial unwillingness of Saudi Arabia and other members of the Organization of Petroleum Exporting Countries (OPEC) cartel to reduce output led to a growing imbalance between supply and demand for crude oil that placed downward pressure on prices. **Figure 10** shows the quarterly supply-and-demand values for crude oil since 2013. Global supply of crude oil began to overtake demand during the first quarter of 2014. Although this supply imbalance showed signs of easing during the middle of 2016, OPEC realized that sustained low crude oil prices had not sufficiently curtailed U.S. production and decided to undertake production cuts sufficient to erode global crude oil

12 *BP Statistical Review of World Energy*, British Petroleum, June 2016, oil production – barrels tab, http://www.bp.com/content/dam/bp/excel/energy-economics/statistical-review-of-world-energy-2016-workbook.xlsx.

inventory levels. The cuts were instituted January 2017 and even included non-OPEC members, such as Russia.[13]

**Figure 10: Global Crude Supply Imbalance (1Q 2013–1Q 2017)**




Sources: International Energy Agency and Energy Commission analysis

The continued increase of excess supply and growing inventory levels weighed heavily on world markets, leading to a collapse of crude oil prices that began during the summer of 2014 and continued through the first quarter of 2015. **Figure 11** illustrates the change in price for Brent North Sea crude oil, an international benchmark that is a good surrogate price for foreign sources of crude oil processed in California refineries.

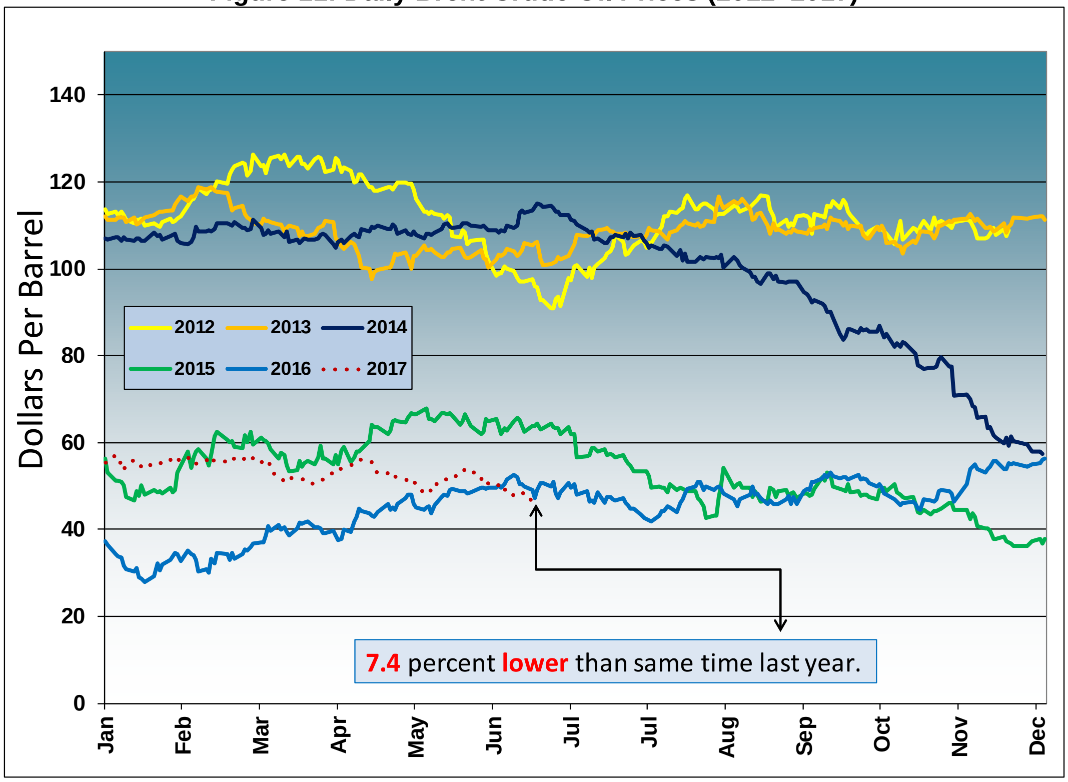
Brent oil prices dropped 59.5 percent between June 19, 2014, and January 13, 2015. The ongoing supply imbalance is certainly the largest factor exerting downward pressure on oil prices, but not the only one. The Energy Commission held a workshop on March 19, 2014 that included an overview of other factors that contributed to the drop in oil prices.[14] Export restrictions for domestically produced oil, growing glut of inventories, and currency market fluctuations are other

13 A copy of the agreement may be accessed at http://www.opec.org/opec_web/static_files_project/media/downloads/press_room/OPEC%20agreement.pdf.

14 Joint Lead Commissioner Workshop on Inputs and Assumptions for Transportation Energy Demand Forecasts, Energy Commission, March 19, 2015. http://www.energy.ca.gov/2015_energypolicy/documents/2015-03-19_presentations.php.

factors that helped contribute to an environment of falling global oil prices.[15] Although prices rebounded somewhat during the first half of 2015, values continued to erode into the first quarter of 2016. This was due to continued oversupply that was partially spurred by additional supplies of oil coming into the market from Iran following the lifting of sanctions on January 16, 2016.[16]

**Figure 11: Daily Brent Crude Oil Prices (2012–2017)**




Source: U.S. EIA

## Crude Oil Logistics and Distribution

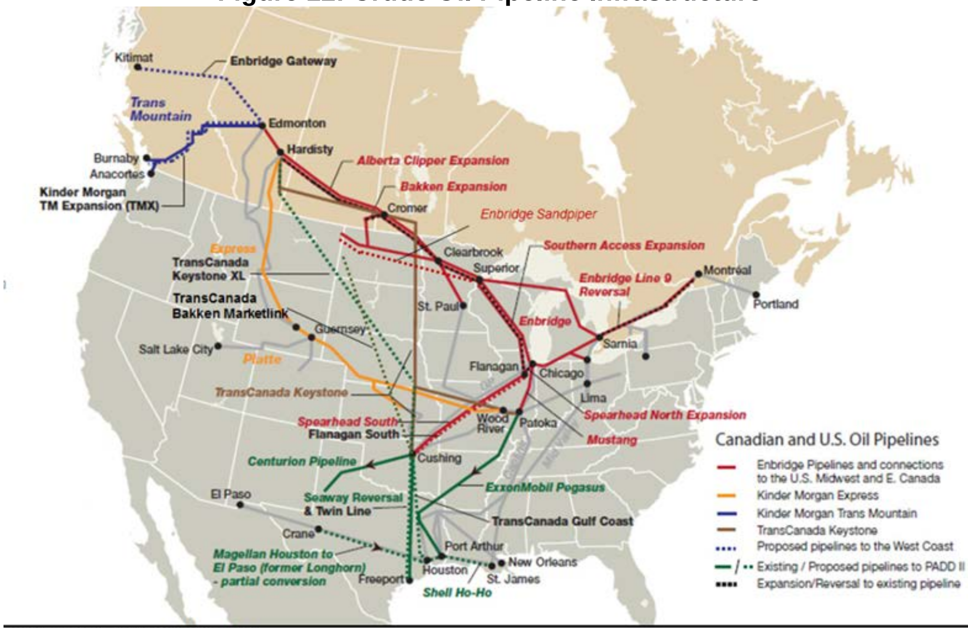
The dramatic increase of domestic crude oil production in the United States exceeded the ability of the crude oil pipeline gathering and distribution infrastructure to keep pace. Consequently, producers sufficiently discounted oil prices to make the more expensive means of rail transportation an economically viable option for refiners outside these shale oil regions. As **Figure 12** shows, there are no crude oil pipelines providing oil to California from outside the state. California refiners have not needed to import domestic crude oil from other states via pipeline due to local sources of oil production, and access to waterborne deliveries from Alaska and foreign sources.

---

15 Ibid, *Recent Trends for Crude Oil Increasing Supply & Declining Prices*, Energy Commission. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-10/TN203900_20150317T082747_Recent_Trends_for_Crude_Oil.pptx.

16 *Statement Relating to the Joint Comprehensive Plan of Action "Implementation Day" of January 16, 2016*, U.S. Department of the Treasury, January 19, 2016. https://www.treasury.gov/resource-center/sanctions/Programs/Pages/iran.aspx.

**Figure 12: Crude Oil Pipeline Infrastructure**




Source: CAPP, Raymond James Ltd.

Marine terminals allow California refiners the flexibility to import crude oil from a variety of locations that meet refiners' quality needs. However, the emergence of discounted crude oil prices and development of rail-loading capability in shale oil states have provided an opportunity for refiners to take advantage of these discounted domestic crude oil sources. Refiners inside and outside the state pursued crude-by-rail (CBR) receiving terminal projects not because refiners were running out of crude oil supplies from existing sources; rather, refiners were trying to obtain discounted crude oil to reduce operating costs and improve profitability.

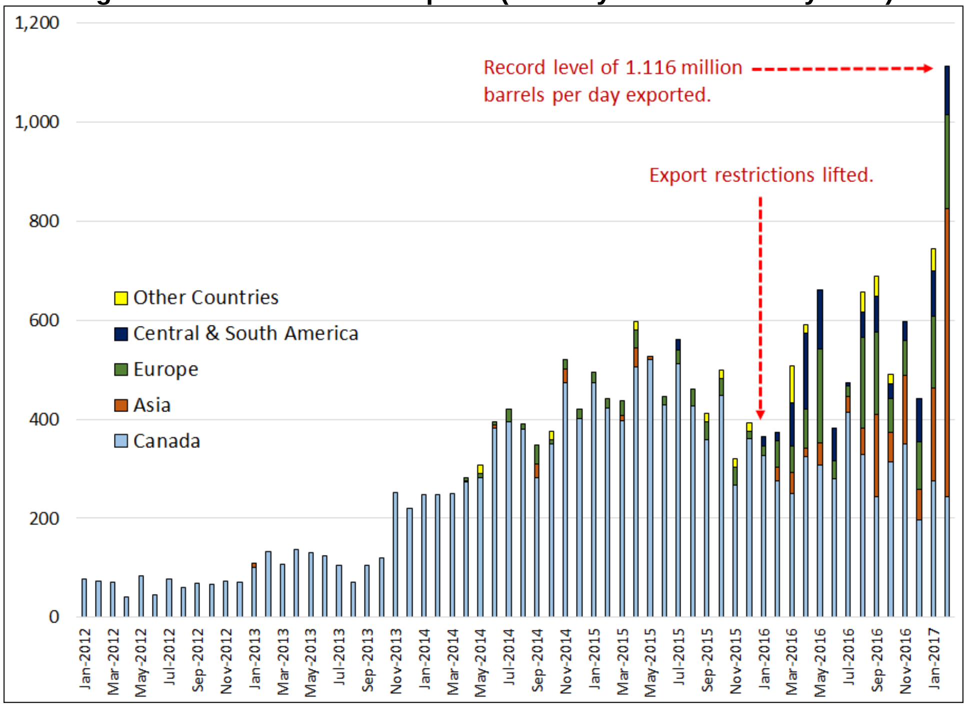
## Crude Oil Export Restrictions Lifted

In addition to the rapid increase of crude oil production temporarily outpacing the ability of oil pipeline transportation capacity, federal restrictions severely limited the quantity of domestic crude oil that could be exported from the United States. Domestically produced crude oil exports to foreign destinations were allowed under specific "license exceptions" identified under federal statute.[17] These restrictions meant that crude oil produced in the United States has to be used in the United States. Although heavy crude oil exports from California were one of few exemptions from the restrictions, none had been exported for several years. This long-standing policy was recently revised to eliminate these export restrictions, freeing companies to send crude oil to any destination.[18] **Figure 13** shows that the change resulted in a significant jump of oil exports and an increased diversity of destination countries.

17 *U.S. Crude Oil Export Policy: Background and Considerations*, Congressional Research Service, March 26, 2014, http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=dfe108c9-cef6-43d0-9f01-dc16e6ded6b4.

18 Changes to the statutory language to eliminate the export restrictions were part of a budget bill signed by President Obama on December 18, 2015.

**Figure 13: U.S. Crude Oil Exports (January 2012—February 2017)**

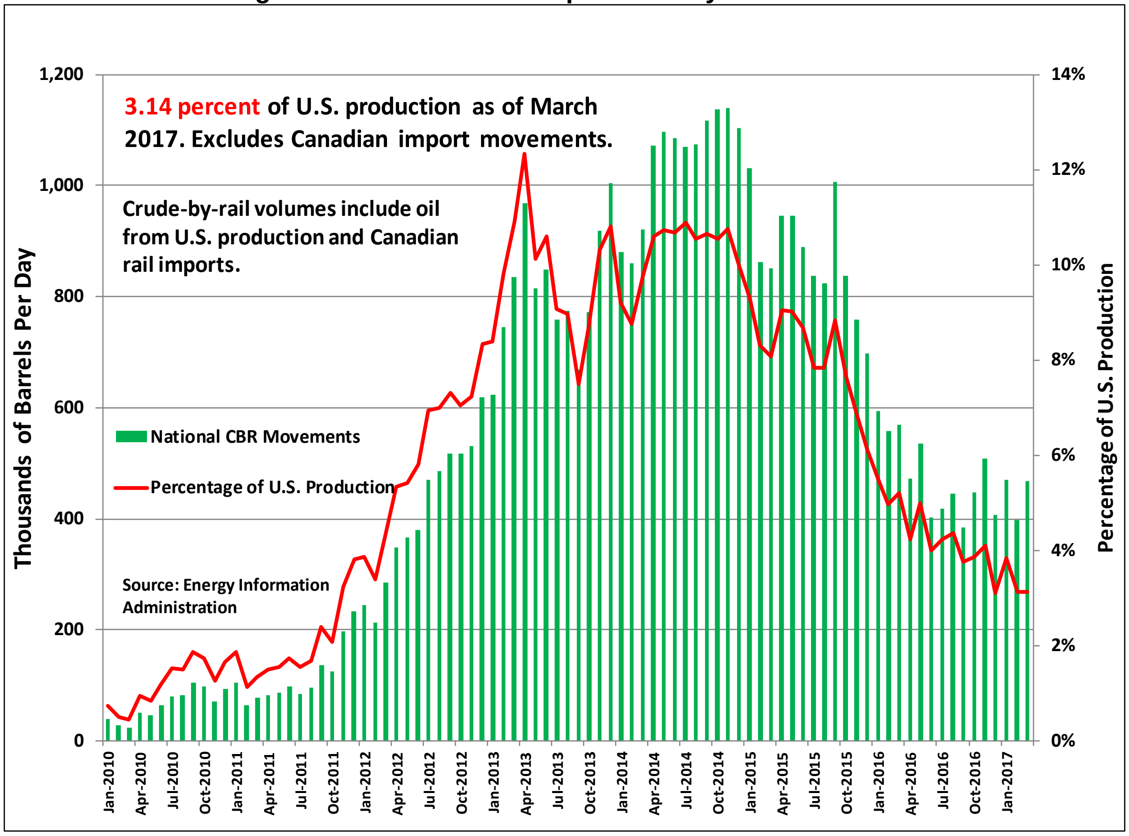



Source: U.S. EIA

## Shift to Crude-by-Rail Increases and Expands to West Coast

CBR is a recent phenomenon. **Figure 14** shows a rapid increase beginning in 2011 as logistical providers ramped up the capability to load crude oil into rail cars at production locations in Canada, North Dakota, Texas, Colorado, New Mexico, Utah, and Wyoming. These projects were completed to take advantage of crude oil price discounts for Canadian and domestic crude oil. The rapid increase in output overwhelmed the capacity of crude oil pipelines to transport to refineries. As a consequence, crude oil prices at these new tight oil (or shale oil) producing regions (such as Bakken in North Dakota) were sufficiently discounted by producers to enable the costlier rail transportation economics to work for refining customers on the West, East, and Gulf Coasts of the United States. The United States Energy Information Administration (U.S. EIA) compiles monthly statistics on crude oil movement by rail tank cars to and from specific regions within the United States. Total volume of crude oil transported by rail tank cars within the United States includes domestically produced oil and imports from Canada. Shipments peaked at 1.1 million BPD during December 2014. Recently, deliveries have declined to fewer than 500,000 BPD as additional pipeline capacity for oil transportation has come on-line and allowed local oil producers access to this cheaper means of pipeline transportation, and the ability to subsequently charge higher prices, lessening the incentive for refining customers to use the more expensive rail transportation option.

**Figure 14: Crude Oil Transportation by Rail Tank Car**




Source: Energy Commission analysis of data from the U.S. EIA

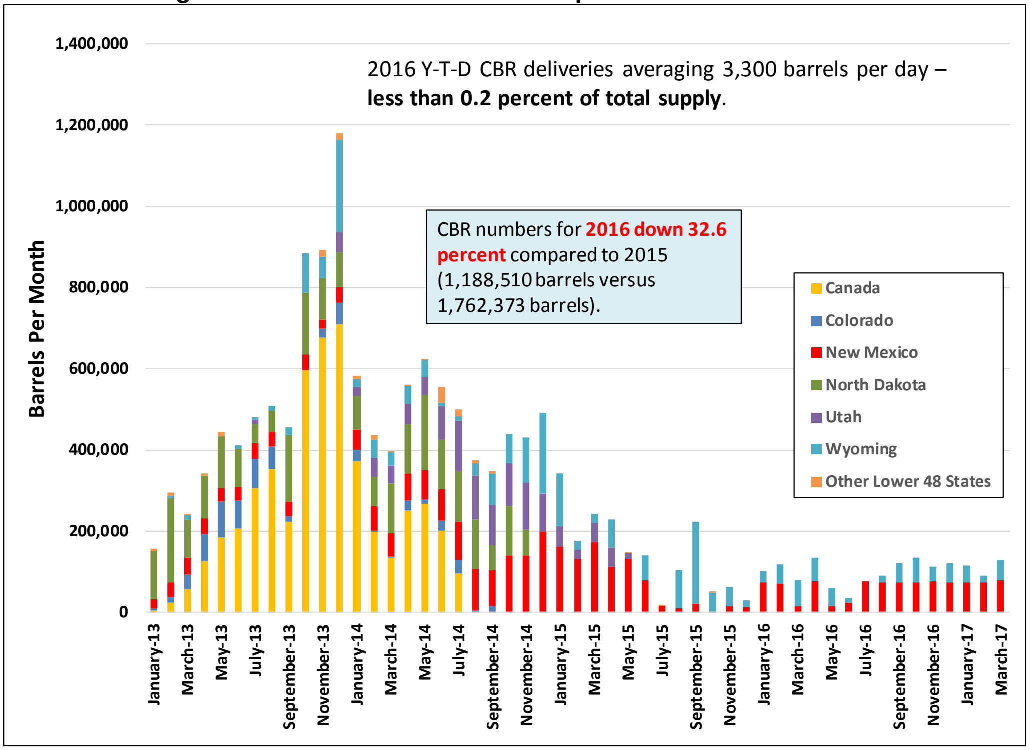
## California Crude-by-Rail Activity

California refiners received 1.1 million barrels of crude oil via rail during 2012. During 2013, California refiners received 6.3 million barrels, a nearly sixfold increase within one year. However, that upward trend did not continue during 2014 as oil imports by rail declined slightly to 5.7 million barrels. **Figure 15** shows monthly CBR deliveries since January of 2013. Volumes peaked during December 2013 at nearly 1.2 million barrels but have since declined to fewer than 0.2 million barrels per month after October 2015.[19] This pattern is similar to the national trend.

Since 2013, deliveries of CBR to California originate from Canada and 10 other states. Canada was the largest source of CBR cargoes during 2013 and 2014, accounting for 41.5 percent of statewide totals, followed by North Dakota at 21 percent and New Mexico at 13 percent. Most recently, CBR deliveries for 2016 totaled 1.2 million barrels, about 32.6 percent lower than the same period during 2015. Since July 2014, Canada's share has dropped to zero and was replaced by imports sourced primarily from New Mexico, with lesser volumes from Wyoming and Utah.

19 Detailed monthly breakdown of CBR deliveries may be accessed at the following link: http://www.energy.ca.gov/almanac/petroleum_data/statistics/2016_crude_by_rail.html.

**Figure 15: California Crude Oil Imports via Rail Tank Cars**

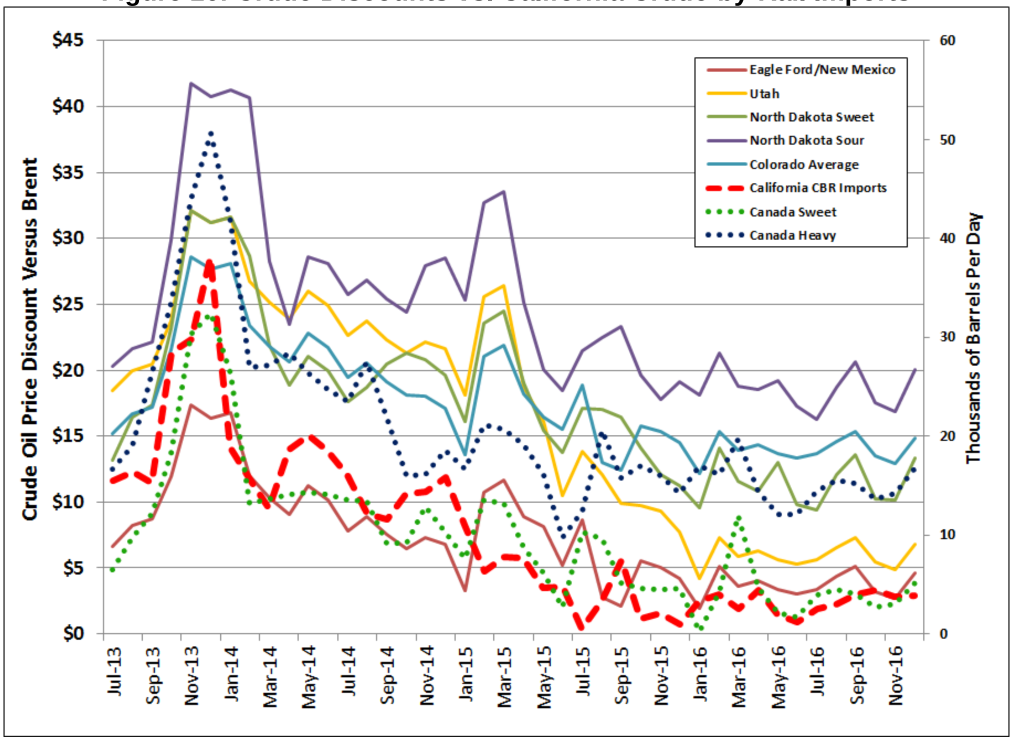



Source: PIIRA data, Energy Commission analysis

CBR deliveries have declined from the peak during December 2013 because of narrowing differences between international crude oil prices (like Brent North Sea) and North American crude oil types (such as Canadian, North Dakota, and Texas). As crude oil output increased in the lower 48 states, shale oil production outpaced the capacity of pipelines to transport the crude oil to market. Producers were forced to discount oil prices such that the higher cost of rail tank car transport would be economical for refiners purchasing their oil. Since mid-2014 more pipeline capacity has become operational, enabling additional shipments of crude oil by pipeline and reducing the need for oil producers to continue with steep discounts for their oil. **Figure 16** illustrates how California monthly CBR imports have changed since early 2014 in relation to the size of these crude oil discounts. The greater the spread between Brent North Sea crude oil and other oil prices, the greater the likelihood that rail transportation economics made sense. But as these discounts narrowed, California CBR imports declined as rail transport became less favorable for California refiners.

Rail delivery represents less than 0.2 percent of 2016 oil supply for California refineries. Foreign crude oil via marine tankers accounted for 328.5 million barrels (54.5 percent), followed by 204.4 million barrels (33.9 percent) from California crude oil received via pipeline and 68.8 million barrels (11.4 percent) from Alaska via marine tankers.

**Figure 16: Crude Discounts vs. California Crude-by-Rail Imports**




Sources: Plains All American, FHR, and Chevron crude oil price bulletins and CBR data from Class 1 railroads

CBR projects are designed to receive shipments of nearly 100 rail tanker cars at a time, referred to as "unit trains." Unlike the more expensive manifest rail car transportation used by a couple of California refiners, unit train shipments are granted a higher priority for rail line access and normally stop only for crew changes until reaching the CBR receiving facility destination. Other types of rail cargo can be granted higher transit priority based on value.[20] CBR rail deliveries in California are a combination of unit trains and manifest cars intermingled with other types of rail cars in mixed freight train deliveries. Rail tank cars carrying crude oil are then dropped off at different rail yards (such as Bakersfield), where they are grouped together for transport to the final refinery destination. In other instances, the rail cars are delivered to locations that unload the crude oil into storage tanks connected to a refinery. Some CBR facilities have been used to transfer crude oil directly from rail tank cars to tanker trucks that are then driven to a refinery.

During 2013 and 2014 some CBR imports were transferred to tanker trucks at two locations in California: Richmond and Sacramento. The Kinder Morgan rail yard in Richmond, California, received between one and two unit trains of crude oil per month. The crude oil was transferred directly from the rail tank cars to tanker trucks through a process referred to as "transloading." Three to four tanker trucks are required to transfer the crude oil from a rail tank car. The other rail terminal that was used to transload crude oil is in Sacramento and is operated by the SAV Patriot Rail Company. The permit for the Richmond operation was issued by the Bay Area Air Quality Management District (BAAQMD), while the one for the SAV Patriot operation was issued

20 Comments by Paul King, California Public Utilities Commission, during *IEPR* workshop, July 20, 2015.

by the Sacramento Air Quality Management District. However, the Sacramento CBR operation ceased activity during early November 2014 after the permit from the Sacramento Air Quality Management District was revoked by the issuing agency. There have been no CBR deliveries to Northern California locations since November 2014.

The likelihood that CBR imports to California will rebound over the next couple of years will depend on the number of CBR receiving facilities that are constructed within the state and the availability of discounted crude oil. Prior to the narrowing of crude oil discounts, more CBR projects were proposed in California. If all the projects had been constructed and operated at full capacity, the contribution of CBR for California refiners could have increased from 1 percent in 2014 to 19 percent by 2017.[21] However, significant local opposition to these projects has blocked additional permits being issued for new CBR facilities. The only completed and operational facility that is designed to handle unit-train size deliveries is the Plains All American terminal near Taft, California.

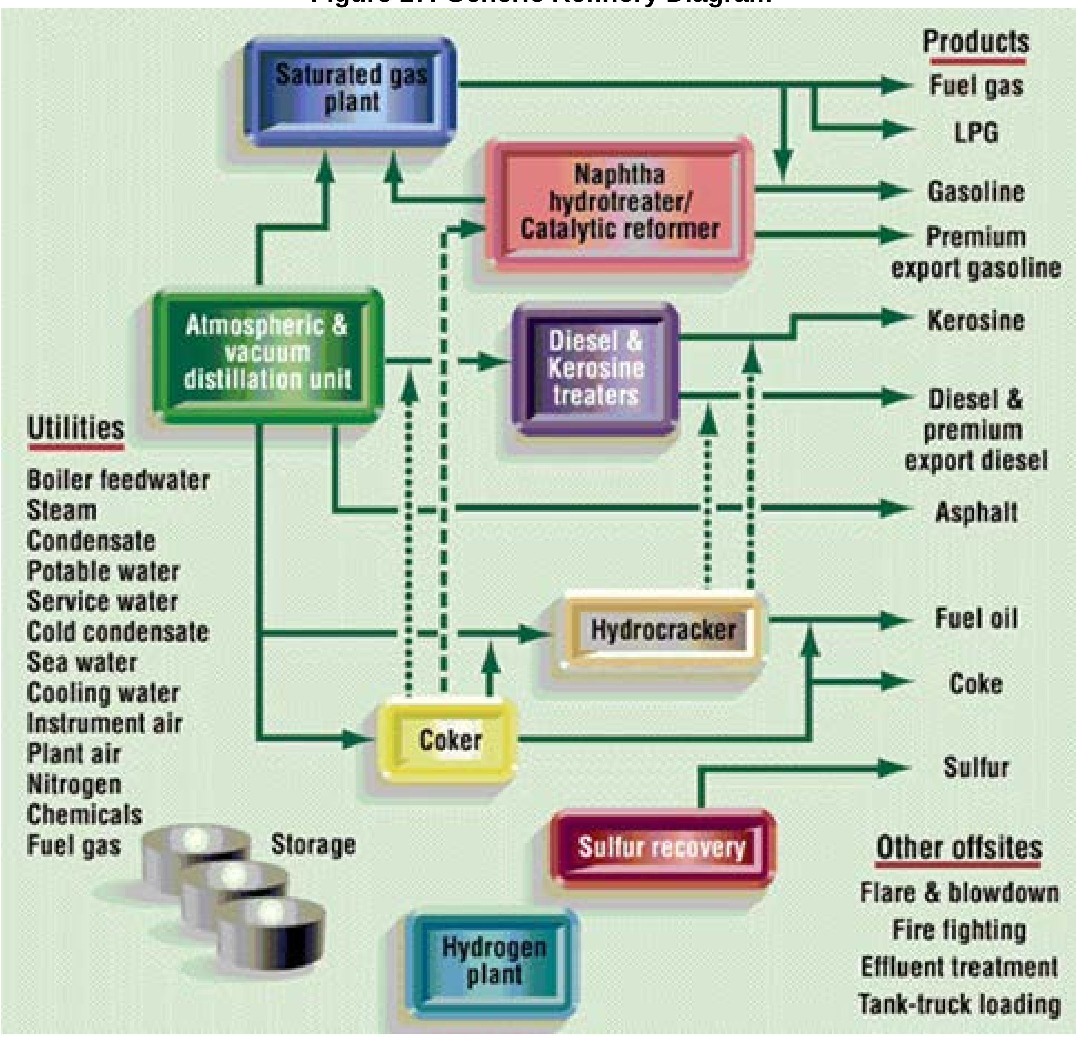
Oil refiners in Washington State began initiating CBR projects before California refiners due to lower rail transportation costs. Washington State refiners are also the biggest consumers of Alaska crude oil, which continues to decline in output, compelling refiners to seek alternative sources of crude oil. The light crude oil from Bakken (North Dakota) is similar in quality to Alaska crude oil, reducing the need to make additional refinery modifications to accommodate the new source of domestic crude oil. There are several CBR facilities in Washington State that are operational, with more planned. Please see **Appendix A** for the status of projects in California and the Pacific Northwest.

21 *Crude Oil Overview & Changing Trends*, IEPR Commissioner Workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, July 20, 2015, slide 35. A link to the presentation is as follows: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205401_20150720T084540_Crued_Oil_Overview__Changing_Trends.pptx.

# CHAPTER 3:
# California's Transportation Fuel Supply Network

Heat, pressure, catalysts, and hydrogen saturation transform crude oil and other refinery feedstocks into finished transportation fuel. Refineries today are complex petrochemical facilities designed to operate in a continuous, steady state. **Figure 17** depicts a generic refinery with all the basic refining process groups. Several types of utilities and off-site services are necessary to maintain safe operations. Further, continuous production of a diverse slate of refined products means that receipts of feedstocks and shipments of transportation fuels must also occur at a constant pace to match the daily operations of the refinery.

**Figure 17: Generic Refinery Diagram**

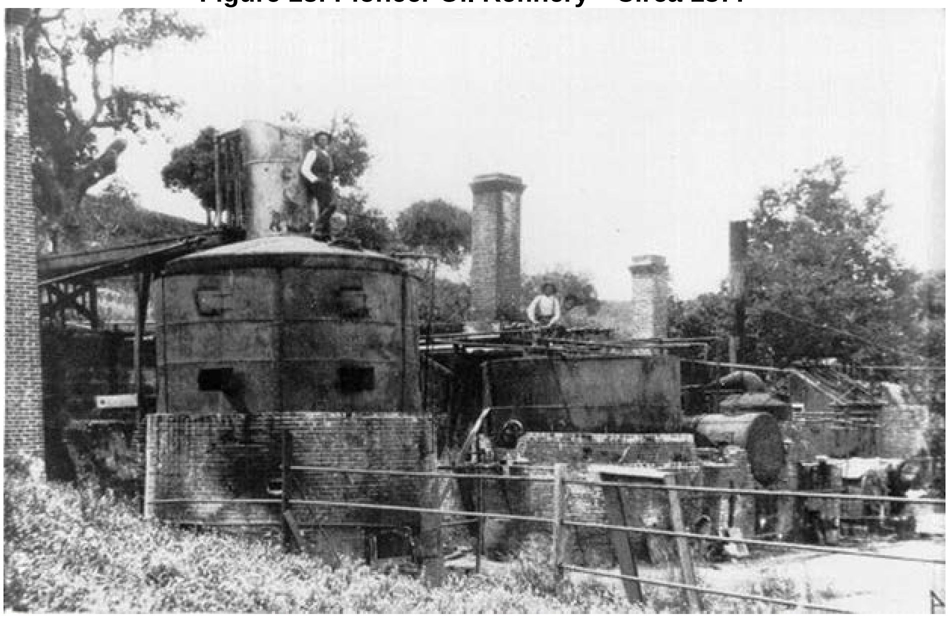



Source: *Oil & Gas Journal*

## California Refinery Operations

Refining history in California has roots back in the 1870s, with one of the first refineries beginning operations in 1877 near Newall, California, with a crude oil processing capacity of 22,000 BPD (refinery pictured in **Figure 18**).[22]

**Figure 18: Pioneer Oil Refinery—Circa 1877**



Source: SANTA CLARITA VALLEY History.com

The earliest refining operation that is still active on the same site is the Phillips 66 refinery in Rodeo, California. The facility began processing crude oil in 1896 under the ownership of the Union Oil Company of California with an initial capacity of 1,600 BPD.[23] Very little evidence remains of the original structures as replacements for pipelines, storage tanks, and processing equipment occurred multiple times over the last 121 years.

The number and ownership of refineries have continued to evolve. In 1982, there were 40 operating refineries in California with a combined crude oil processing capacity of 2.6 million BPD. These facilities operated at an average utilization rate of 61.8 percent and produced an average of 956,000 BPD of gasoline, 184,000 BPD of jet fuel, and 241,000 BPD of distillates.[24] By 2016, the number of operating transportation fuel producing refineries had condensed to 15 with a crude oil processing capacity of 1.884 million BPD, an average utilization rate of 85.6 percent with output of transportation fuels of 1.007 million BPD of gasoline, 281,000 BPD of jet fuel, and

---

22 Santa Clarita Valley history. A link to additional details associated with this refinery in Newhall can be accessed at http://www.scvhistory.com/scvhistory/ap2926.htm.

23 Information applicable to the initial crude oil processing capacity may be accessed as the following site: https://www.revolvy.com/main/index.php?s=Rodeo%20San%20Francisco%20Refinery.

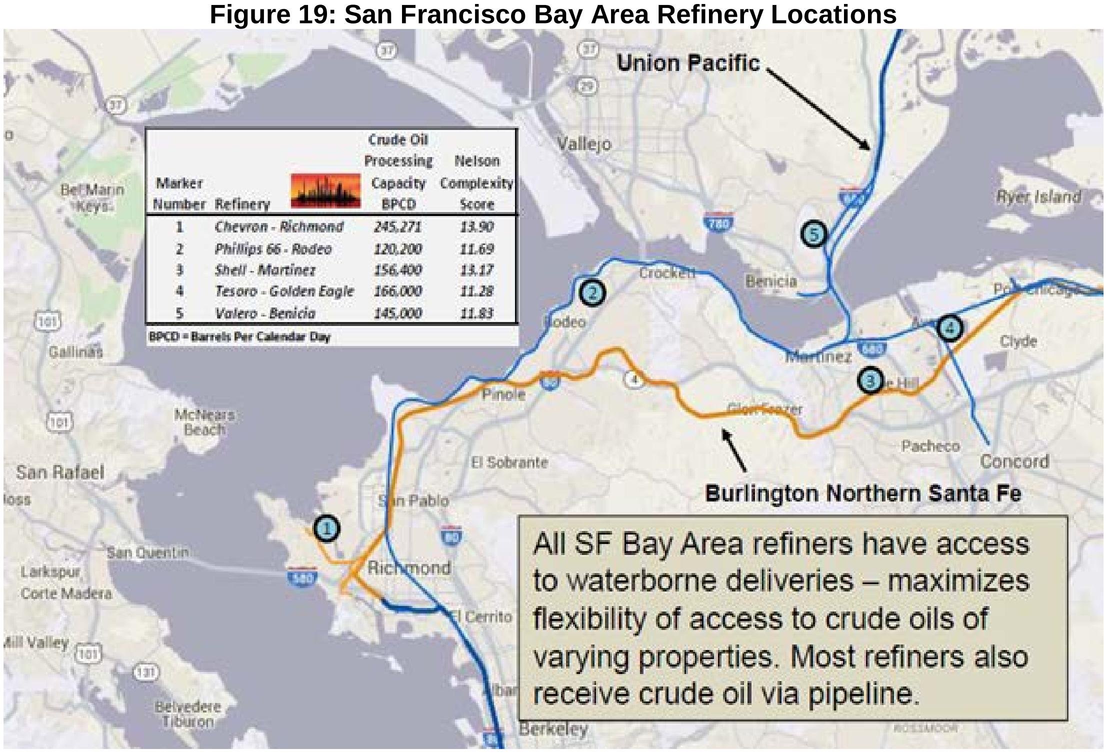
24 *Utilization rate* is a measure of how much crude oil was processed at a given refinery or group of refineries relative to the maximum daily processing capacity.

360,000 BPD of distillates.[25] Even with fewer than half as many refineries, companies were able to produce greater quantities of transportation fuel by operating at higher utilization rates and use of expanded and/or additional refinery process equipment that did not exist in 1982. **Table 1** shows how ownership of the current operating refineries has changed since the initial opening of each facility.[26]

During 2016, California's 15 refineries processed about 1.612 million barrels of crude oil each day.[27] Not all refineries are capable of producing gasoline and diesel fuels that meet California specifications. However, these facilities are an important source of other types of refined products such as asphalt and lubricating oils vital to business. Thirteen of the 15 operating fuel-producing refineries are the primary source of transportation fuels for California and Nevada, while also supplying fuels to Arizona, Oregon, Central America, and South America.

**Figure 19** shows the location of refineries in the greater San Francisco Bay Area. The facilities have access to crude oil receipts via marine vessel, as well as the ability to receive crude oil via three pipelines originating in southern San Joaquin Valley.

**Figure 19: San Francisco Bay Area Refinery Locations**



| Marker Number | Refinery | Crude Oil Processing Capacity BPCD | Nelson Complexity Score |
|---|---|---|---|
| 1 | Chevron - Richmond | 245,271 | 13.90 |
| 2 | Phillips 66 - Rodeo | 120,200 | 11.69 |
| 3 | Shell - Martinez | 156,400 | 13.17 |
| 4 | Tesoro - Golden Eagle | 166,000 | 11.28 |
| 5 | Valero - Benicia | 145,000 | 11.83 |

BPCD = Barrels Per Calendar Day



Source: Oil Change International map, U.S. EIA refinery data, and Energy Commission analysis

25 Alon USA - Bakersfield, Greka Energy - Santa Maria, Lunday Thagard – South Gate, and Paramount refineries have been excluded from the calculations since these facilities were not processing crude oil during 2016. Operating refineries had an average crude oil throughput of 1.612 million BPD compared to a crude oil processing capacity of 1.884 million BPD.

26 A detailed list that includes refineries that have closed, been merged or idled is available at the following link: http://www.energy.ca.gov/almanac/petroleum_data/refinery_history.html.

27 A link to a listing of California refineries and the associated crude oil processing capacity is as follows: http://www.energy.ca.gov/almanac/petroleum_data/refineries.html.

**Table 1: Ownership Change of California Fuel Producing Refineries**

| California Fuel Producing Refinery Facilities | Began Operations | Ownership Information | Current Crude Capacity (Barrels/Day) |
|---|---|---|---|
| Chevron, El Segundo Refinery | 1912 | Standard Oil Co: 1912-1926<br>Standard Oil Company of California (Socal): 1926-1977<br>Chevron USA Inc: 1977-2001<br>ChevronTexaco Corp: 2001-2005<br>Chevron Corp: 2005-Present | 269,000 |
| Chevron, Richmond Refinery | 1902 | Pacific Coast Oil: July 7, 1902-1906<br>Standard Oil Co: 1906-1926<br>Standard Oil Company of California (Socal): 1926-1977<br>Chevron USA Inc.: 1977-2001<br>ChevronTexaco Corp: 2001-2005<br>Chevron Corp: 2005-Present | 245,271 |
| Kern Oil & Refining Company, Bakersfield Refinery | 1934 | El Tejon Oil & Refining Co: 1934-1943<br>Kreiger Oil Co: 1943-1945<br>Douglas Oil Co: 1945-1962<br>Continental Oil: 1962-1966<br>Edgington Oil/Signal Oil & Gas: 1966-1971<br>Kern County Refinery Inc. (Charter Oil Co.): 1971-1976<br>Kern County Refinery Inc. (Privately Held): 1976-1982<br>Kern Oil & Refining Co: 1982-Present | 26,000 |
| PBF Energy, Torrance Refinery | 1907 | Vacuum Oil Co: 1907-1929<br>General Petroleum Corporation of Calif: 1929-1931<br>Standard Oil Company of New York-Vacuum Corp (Socony): 1931-1934<br>Socony-Vacuum Oil Company, Inc.: 1934-1955<br>Socony Mobil Oil Co: 1955-1966<br>Mobil Oil Corp: 1966-2000<br>ExxonMobil: 2000-July 2016<br>PBF Energy: July 2016-Present | 151,300 |

| California Fuel Producing Refinery Facilities | Began Operations | Ownership Information | Current Crude Capacity (Barrels/Day) |
|---|---|---|---|
| Phillips 66, Rodeo Refinery | 1896 | Union Oil Co of Calif: 1896-1983<br>Unocal: 1983-1997<br>Tosco Corp: 1997-2001<br>Phillips: 2001-2002<br>ConocoPhillips: 2002-May 2012<br>Phillips 66: May 2012-Present | 78,400 |
| Phillips 66, Santa Maria Refinery | 1955 | Union Oil Co of Calif: 1955-1983<br>Unocal: 1983-1997<br>Tosco Corp: 1997-2001<br>Phillips: 2001-2002<br>ConocoPhillips: 2002-May 2012<br>Phillips 66: May 2012-Present | 41,800 |
| Phillips 66, Wilmington Refinery | 1917 | Union Oil Co of Calif: 1917-1983<br>Unocal: 1983-1997<br>Tosco Corp: 1997-2001<br>Phillips: 2001-2002<br>ConocoPhillips: 2002-May 2012<br>Phillips 66: May 2012-Present | 139,000 |
| San Joaquin Refining Company, Bakersfield Refinery | 1969 | San Joaquin Refining Co: 1969-Present | 15,000 |
| Shell Oil Products US, Martinez Refinery | 1915 | Shell Company of Calif: 1915-1939<br>Shell Oil Company, Inc.: 1939-1949<br>Shell Oil Co: 1949-1998<br>Equilon Enterprises (joint venture of Shell Oil Co. and Texaco Inc.): 1998-2002<br>Shell Oil Co: 2002-Present | 156,400 |
| Tesoro Refining & Marketing, Carson Refinery | 1938 | Richfield Oil Corp: 1938-1966<br>Atlantic Richfield Company (ARCO): 1966-2000<br>BP West Coast Products: 2000-June 2013<br>Tesoro Refining & Marketing: June 2013-Present | 256,830 |

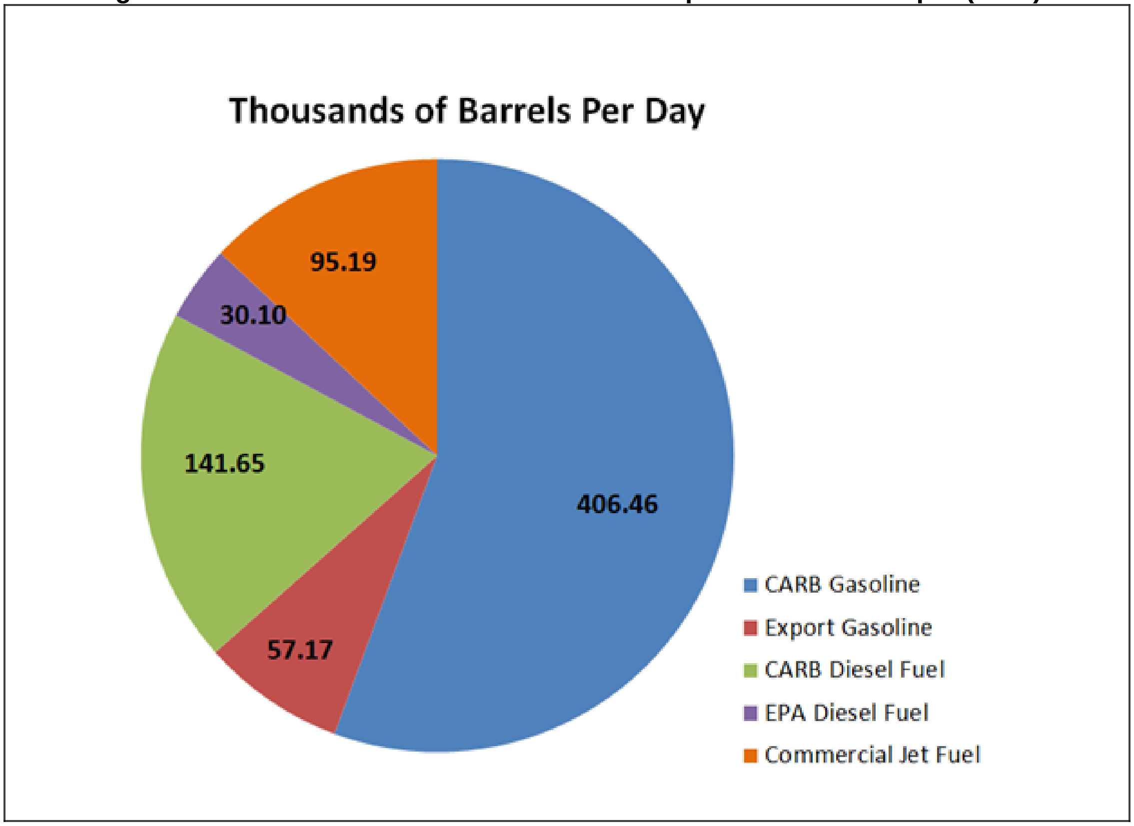
| California Fuel Producing Refinery Facilities | Began Operations | Ownership Information | Current Crude Capacity (Barrels/Day) |
|---|---|---|---|
| Tesoro Refining & Marketing Co., Golden Eagle Refinery, Martinez/Avon | 1913 | Associated Oil Co: 1913-1937<br>Tidewater Associated Oil Co: 1937-1966<br>Phillips Petroleum: 1966-1976<br>Tosco Corp: 1976-2000<br>Ultramar Diamond Shamrock: 2000-2002<br>Valero Refining Co: 2002<br>Tesoro Refining: 2002-Present | 166,000 |
| Tesoro Refining & Marketing Co., Wilmington Refinery | 1923 | California Petroleum Corp: 1923-1928<br>Texas Company: 1928-1959<br>Texaco, Inc.: 1959-1998<br>Equilon Enterprises (joint venture of Shell Oil Co. and Texaco Inc.): 1998-2002<br>Shell Oil Co: 2002-2007<br>Tesoro Corp: 2007-Present | 98,340 |
| Valero, Benicia Refinery | 1968 | Exxon Co USA: 1968-2000<br>Valero Refining Co: 2000-Present | 145,000 |
| Valero, Wilmington Refinery | 1969 | Champlin Petroleum Co: 1969-1987<br>Union Pacific Resources Co: 1987-1988<br>Ultramar Refining: 1988-1997<br>Ultramar Diamond Shamrock: 1997-2002<br>Valero Refining Co: 2002-Present | 85,000 |

Source: Energy Commission

The Northern California refineries produced 730,600 BPD of gasoline, diesel, and jet fuel during 2016. As shown in **Figure 20**:

- 406,500 BPD (55.6 percent of Northern California refinery output) was California Reformulated Gasoline (RFG) Blendstock for Oxygenate Blending (CARBOB)
- 57,200 BPD (8 percent) was gasoline for export outside the state to locations in Northern Nevada and foreign markets
- 142,000 BPD (19 percent) was California Air Resources Board (CARB)-compliant diesel fuel
- 30,000 BPD (4 percent) was gasoline for export outside the state to northern Nevada and South America
- 95,000 BPD (13 percent) of commercial jet fuel, with the majority of this volume distributed to Northern California airports

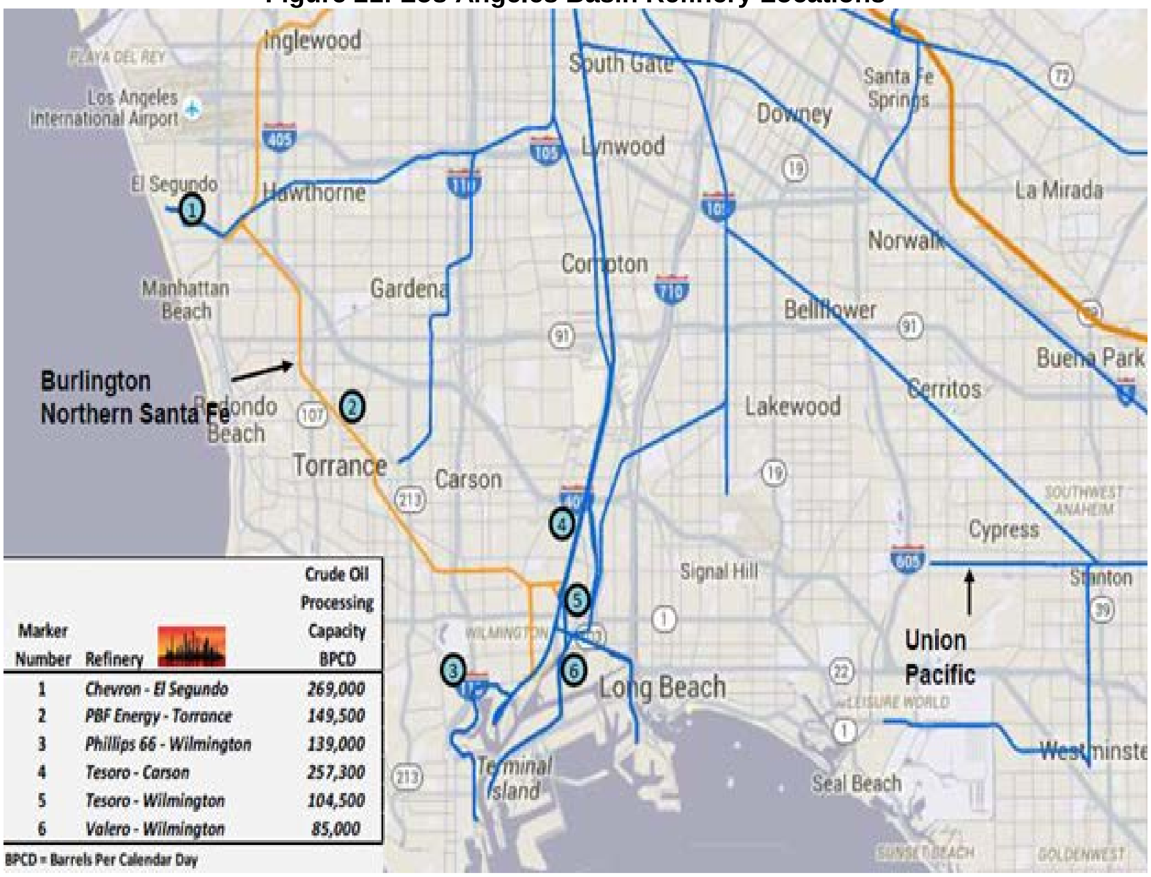
**Figure 20: Northern California Refineries Transportation Fuel Output (2016)**




Source: Energy Commission

**Figure 21** shows the location of the Southern California refineries in the greater Los Angeles area. All have access to crude oil receipts via marine vessel, as well as the ability to receive crude oil via two pipelines originating in southern San Joaquin Valley. Most of the refineries are situated further inland than the Northern California facilities, but the associated linkages with marine wharves are via a network of crude oil and refined product pipelines. The Chevron El Segundo refinery is the only facility that uses mooring buoys (rather than a wharf) to transfer crude oil and petroleum products between marine vessels and the refinery. Another difference between the two regions is that all refiners in Northern California own their marine terminals, whereas the marine terminal docks in Southern California are owned by the cities of Los Angeles and Long Beach, and are leased to refining and logistics companies such as Kinder Morgan.

**Figure 21: Los Angeles Basin Refinery Locations**

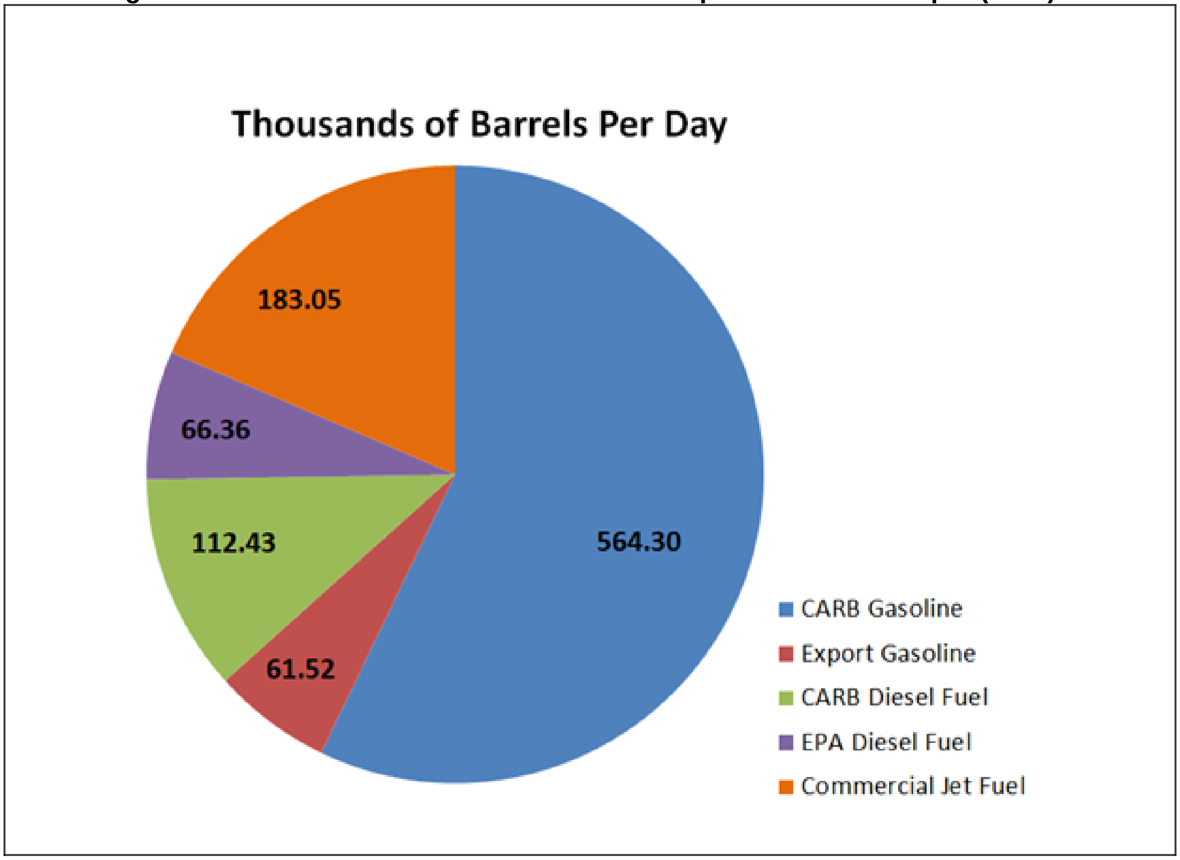



Source: Oil Change International map, U.S. EIA refinery data, and Energy Commission analysis

The Southern California refineries produced 905,500 BPD of gasoline, diesel, and jet fuel during 2016. As shown in **Figure 22**:

- 564,300 BPD (57.1 percent of Southern California transportation fuel output) consisted of CARBOB
- 61,500 BPD (6.2 percent) was gasoline destined for export outside the state, primarily to locations in Arizona and southern Nevada.
- 112,000 BPD (11 percent) was CARB compliant diesel fuel
- 66,400 BPD (6.7 percent) of non-California diesel fuel shipped to Arizona and southern Nevada, with rare shipments to foreign destinations
- 183,000 BPD (18.5 percent) of commercial jet fuel with the majority of this volume distributed to Southern California airports and lesser quantities to airports in Phoenix and Las Vegas

**Figure 22: Southern California Refineries Transportation Fuel Output (2016)**

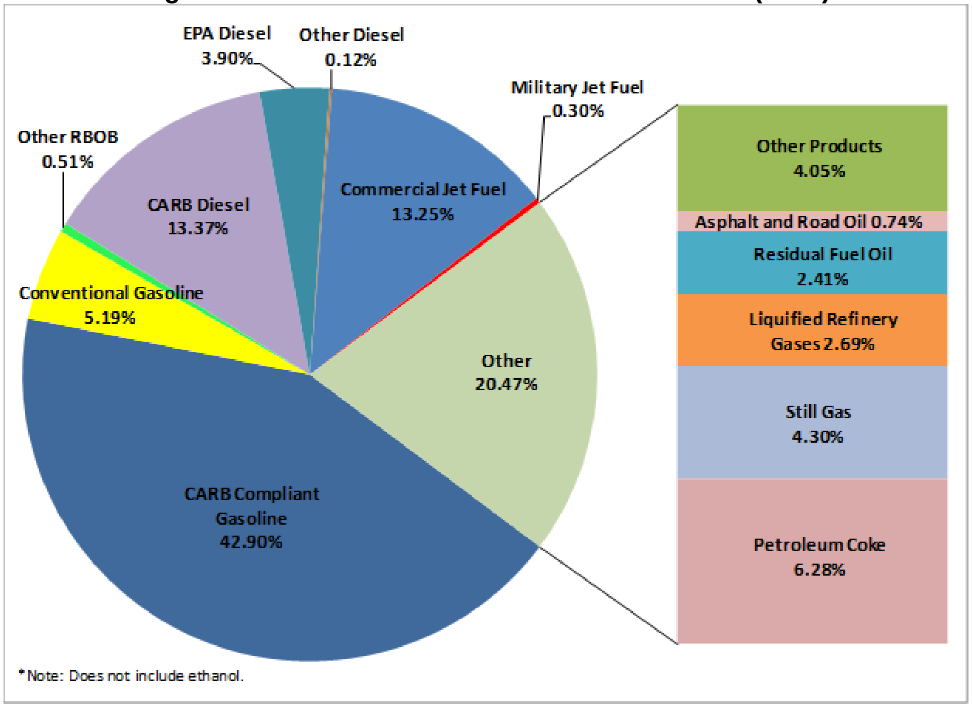



Source: Energy Commission

Both regions produce a remarkably similar proportion of gasoline from their total transportation fuel output, 63.5 percent versus 63.4 percent for Northern and Southern California, respectively. The Northern California diesel fuel proportion of 23.5 percent is greater than Southern California's 18 percent, but the jet fuel proportion is smaller at 13 percent compared to the 18.5 percent proportion for Southern California refineries. Despite a greater portion of jet fuel produced in Southern California, output is insufficient in meeting local demand and must be augmented with foreign imports that are sourced mainly from Southeast Asian countries.

Not only do refineries in California produce nearly all of the transportation fuels needed to meet statewide demand, they also produce other types of refined products and coproducts (such as sulfur). **Figure 23** illustrates the additional refined petroleum products and the relative proportion (20.5 percent) of statewide refinery output during 2016, referred to as a *product slate.*

**Figure 23: Product Slate of California Refineries (2016)**




Source: Energy Commission

Still, gas is a by-product of crude oil refining and is used as a fuel, along with purchased natural gas, to create process steam and hydrogen. Residual fuel oil is consumed primarily by marine vessels as bunker fuel that has been blended with higher sulfur diesel fuel. Bunker fuel sulfur content limits are scheduled to be lowered through international agreements. A January 2020 change has the potential to increase demand for ultra-low-sulfur diesel fuel in the vessel bunkering business and is one of the topics discussed in detail in the "California's Transportation Fuel Supply Issues" section of this chapter.

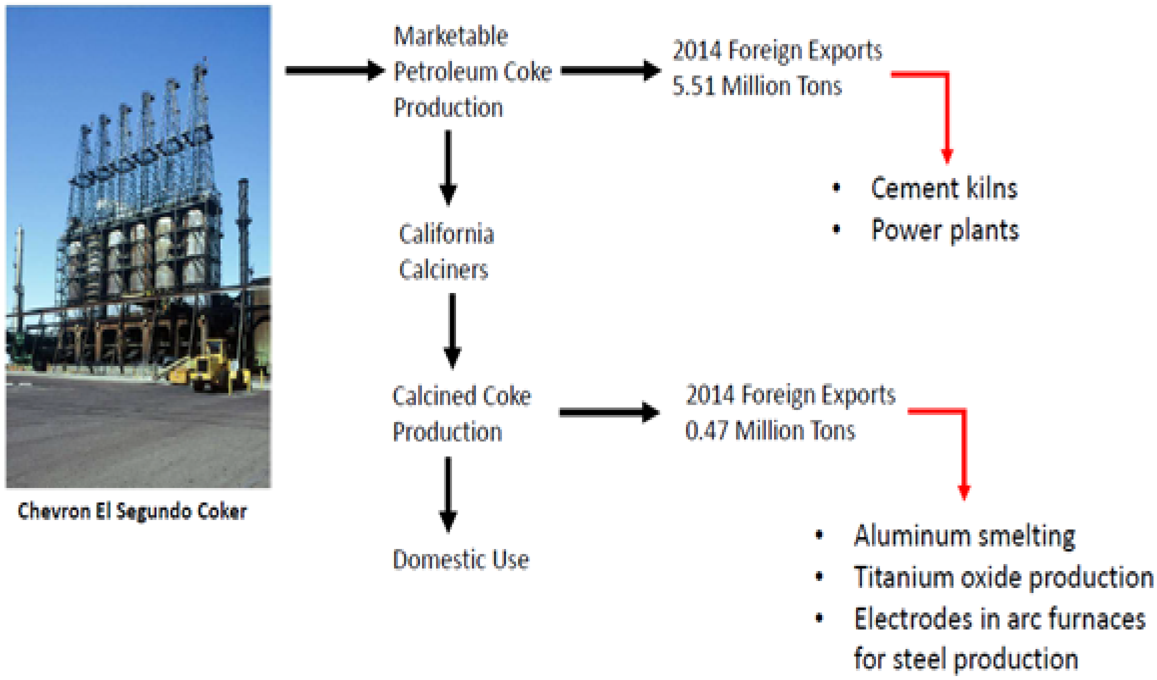
Petroleum coke is an oddity of refining as it is a by-product of the final refining step referred to as *coking*. **Figure 24** depicts California's petroleum coke disposition and the respective quantities of export and intended uses during 2014. About 92 percent of California petroleum coke exported to foreign countries was sent out as *green coke* (unprocessed coke directly from the coker), with the remaining portion further processed in California calciners to remove all traces of moisture and hydrocarbon content to yield a nearly pure carbon solid.[28]

**Figure 25** breaks down the destination countries for petroleum coke (green coke) during 2014. Less than a third (26.6 percent) of total exports was shipped out of Northern California, with 76 percent of total exports going to Southeast Asia.

---

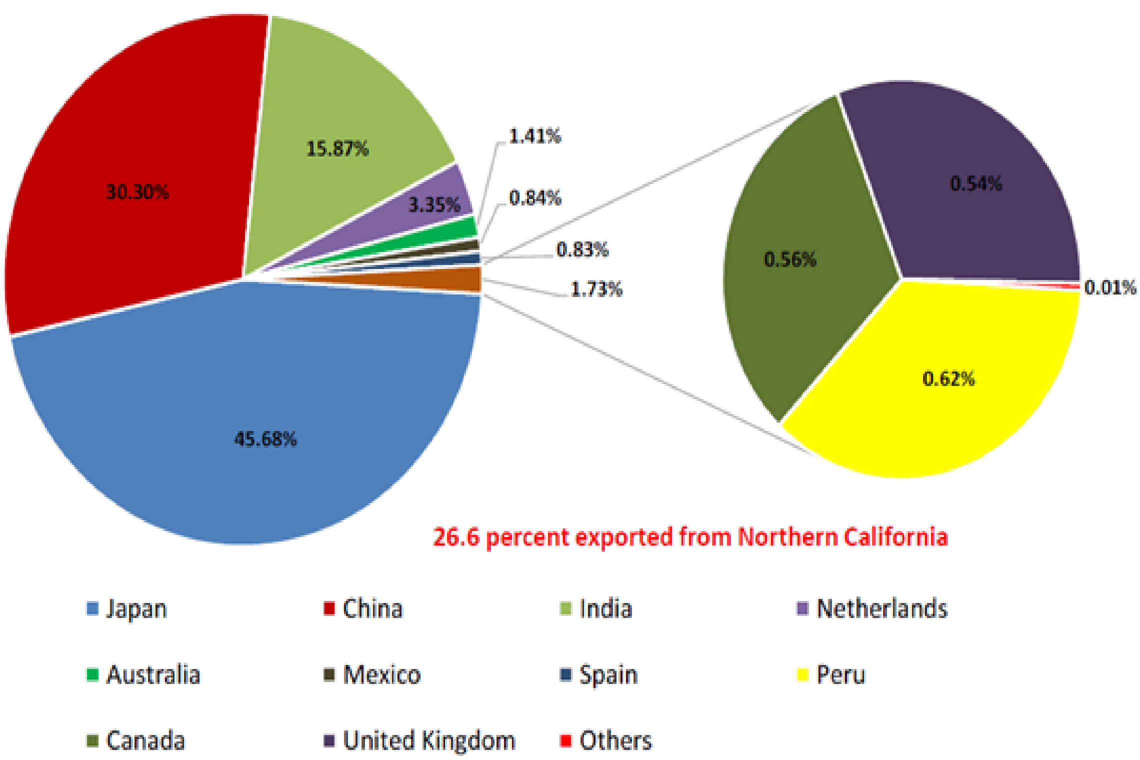
28 A detailed description of calcining and end uses for calcined petroleum coke as contained in the following publication – *The History and Future Challenges of Calcined Petroleum Coke Production and Use in Aluminum Smelting, Journal of The Minerals, Metals & Materials Society (TMS)*, Vol. 67, No. 2, 2015. A link to this journal article is as follows: http://download.springer.com/static/pdf/372/art%253A10.1007%252Fs11837-014-1248-9.pdf?originUrl=http%3A%2F%2Flink.springer.com%2Farticle%2F10.1007%2Fs11837-014-1248-9&token2=exp=1496967585~acl=%2Fstatic%2Fpdf%2F372%2Fart%25253A10.1007%25252Fs11837-014-1248-9.pdf%3ForiginUrl%3Dhttp%253A%252F%252Flink.springer.com%252Farticle%252F10.1007%252Fs11837-014-1248-9*~hmac=fcf6b14c443295170eea1b7e7ea4047aa201306bb76a5b58d440f16bd1f96c6b.

**Figure 24: Petroleum Coke Disposition (2014)**




Source: Energy Commission

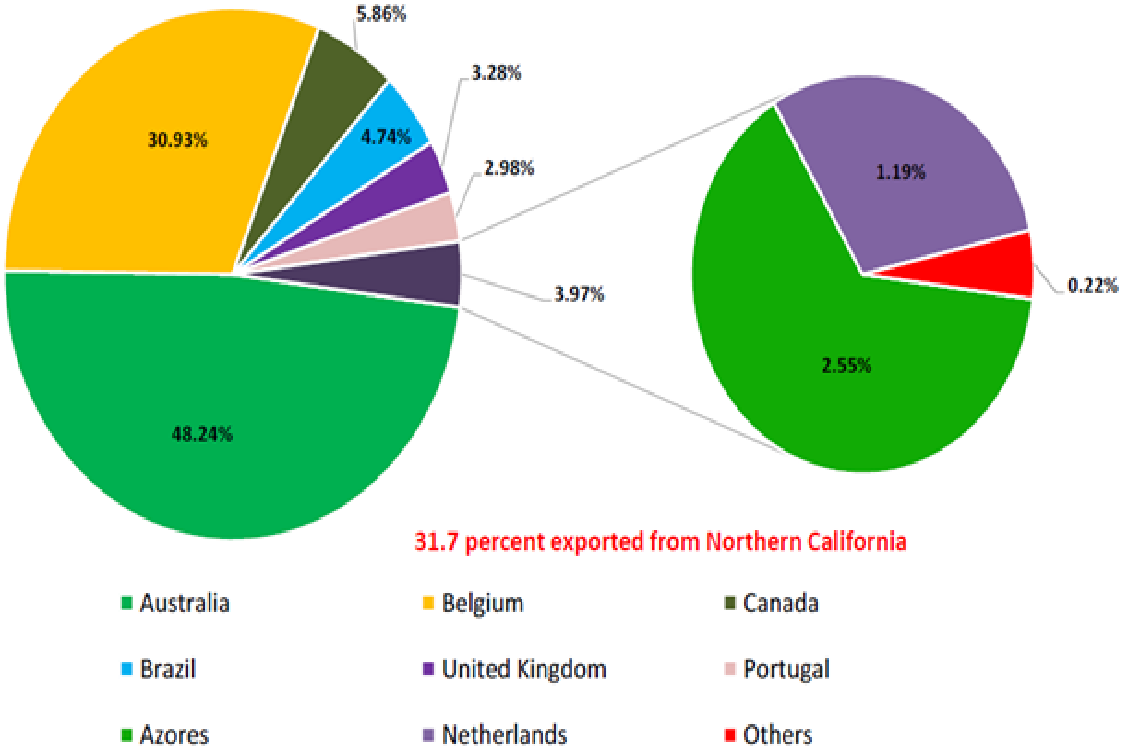
**Figure 25: California Petroleum Coke Export Destinations (2014)**




Source: Energy Commission analysis of iPIER subscription data

**Figure 26** breaks down the destination countries for calcined coke exported from the state during 2014. *Calcined coke* is combined with coal tar pitch to create carbon anodes.[29] As was the case with petroleum coke, less than a third (31.7 percent) of total exports were shipped out of Northern California, with nearly half (48.2 percent) of total exports going to Australia for aluminum production and 30.9 percent to Belgium for production of carbon anodes necessary for aluminum production.

**Figure 26: California Calcined Coke Export Destinations (2014)**




Source: Energy Commission analysis of Port Import Export Reporting Service data

## Transportation Fuel Consumption

There are a variety of transportation fuels used in California, derived from both petroleum and renewable feedstocks. "Traditional" transportation fuels in this context include finished gasoline (base gasoline and the ethanol), finished diesel fuel (diesel fuel, biodiesel, and renewable diesel fuel), and commercial jet fuel. During 2016, these fuels accounted for 23 billion gallons combined. Other transportation fuels not included in this grouping are military jet fuel, aviation gasoline, propane, compressed natural gas (CNG), liquefied natural gas (LNG), electricity, hydrogen, and bunker fuel. Diversity of transportation fuels has evolved over the last several years, driven by federal and state fuel regulations and changing consumer preferences for vehicles.

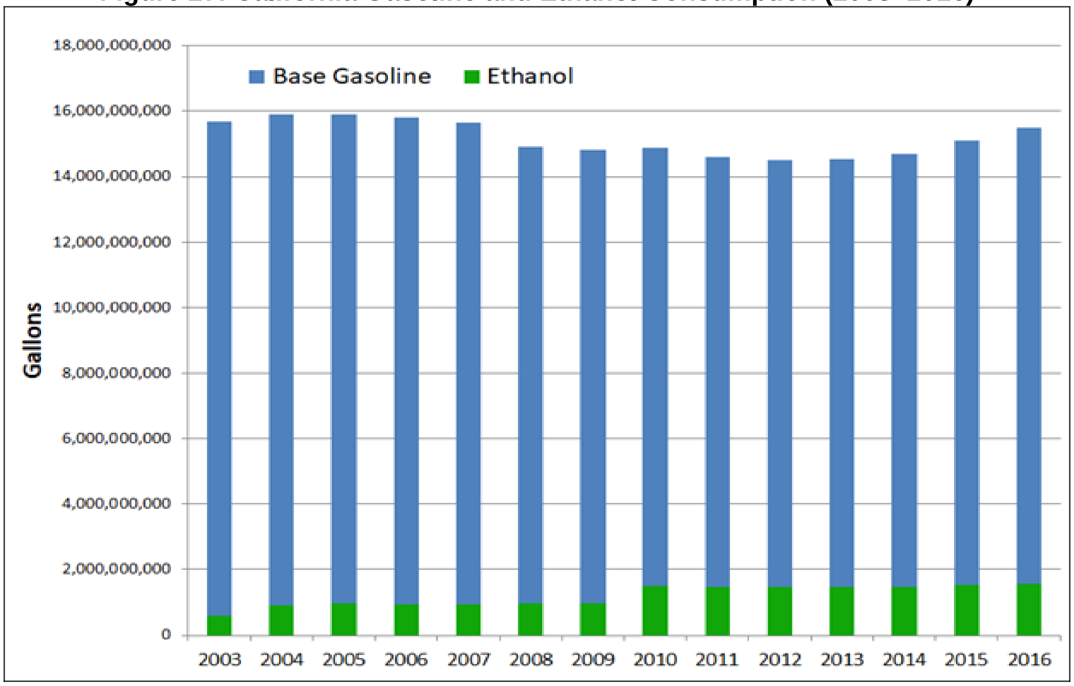
---

29 Mannweiler, Ulrich, Werner K. Fischer, and Raymond C. Perruchoud, 2009. *Carbon Products: A Major Concern to Aluminum Smelters*, A link to this research paper is as follows: https://www.rd-carbon.com/data/documents/publications/raw-materials-carbon-products/carbon_products_-_a_major_concern.pdf.

## Finished Gasoline and Ethanol

Finished gasoline is the leading source of traditional transportation fuel in California, accounting for 15.5 billion gallons during 2016 or 67.2 percent of total. Not all of this fuel was petroleum-based, as evidenced by the growing use of ethanol depicted in **Figure 27**.

**Figure 27: California Gasoline and Ethanol Consumption (2003–2016)**




Source: Energy Commission analysis

**Table 2** breaks down finished gasoline into the base petroleum portion, referred to as CARBOB, and the fuel-grade ethanol. Ethanol use has increased from an average concentration of 3.75 percent by volume in 2003 to 10.09 percent by volume during 2016. Ethanol use has exceeded the ethanol "blend wall"[30] through growing sales of E85 (generic term for fuel that is between 51 percent and 83 percent ethanol) that reached a record 18.68 million gallons. Although finished gasoline consumption declined 8.9 percent between 2004 and 2012, strong recovery from the recession and continued population growth have pushed consumption up by 6.9 percent between 2012 and 2016, edging closer to a record high.

## Finished Diesel Fuel, Biodiesel, and Renewable Diesel Fuel

Diesel fuel is the third largest consumed traditional transportation fuel in California, accounting for 3.70 billion gallons during 2016 or 16 percent of total. Not all of this fuel was petroleum-based, as biodiesel and renewable diesel fuel growth have accelerated over the last four years, spurred on by obligations under the Low Carbon Fuel Standard (LCFS), to reach record levels of 167.52 million and 249.34 million gallons, respectively. Consumption by diesel fuel types is depicted in **Figure 28**.

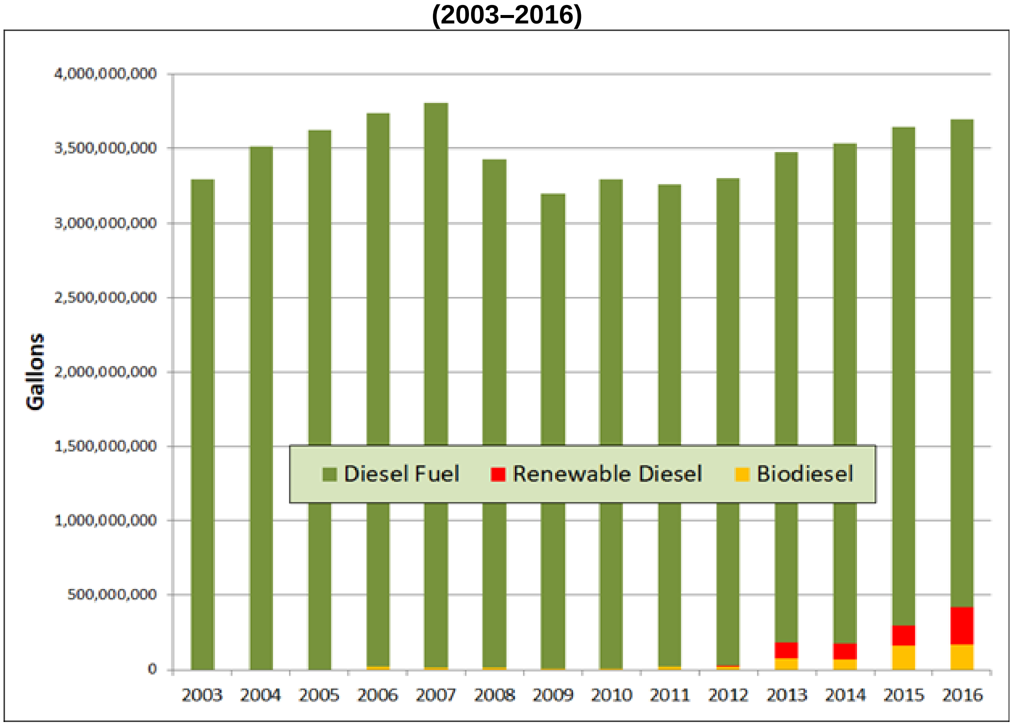
30 The "blend wall" is the maximum amount of ethanol that can be included in finished gasoline (10 percent by volume) per CARB Phase II gasoline regulations.

**Table 2: California Gasoline and Ethanol Consumption (2003–2016)**

| Year | Finished Gasoline Consumption Gallons | CARBOB Consumption Gallons | E85 Consumption Gallons | Fuel Ethanol[4] Consumption Gallons |
|---|---|---|---|---|
| 2003 | 15,688,264,000 | 15,099,521,000 | | 588,742,569 |
| 2004 | 15,909,201,916 | 15,009,775,916 | | 899,426,256 |
| 2005 | 15,894,985,843 | 14,941,286,692 | | 953,699,151 |
| 2006 | 15,821,102,372 | 14,871,830,150 | 8,000 | 949,272,222 |
| 2007 | 15,658,306,800 | 14,718,689,948 | 155,847 | 939,616,852 |
| 2008 | 14,917,598,979 | 13,947,372,953 | 770,983 | 970,226,026 |
| 2009 | 14,814,028,519 | 13,849,875,825 | 1,643,497 | 964,152,694 |
| 2010 | 14,861,605,386 | 13,373,335,223 | 2,930,034 | 1,488,270,163 |
| 2011 | 14,606,188,413 | 13,141,949,904 | 5,027,316 | 1,464,238,509 |
| 2012 | 14,486,189,542 | 13,032,902,923 | 6,482,868 | 1,453,286,619 |
| 2013 | 14,540,241,379 | 13,079,881,255 | 8,799,981 | 1,460,360,124 |
| 2014 | 14,701,647,403 | 13,223,514,835 | 11,066,428 | 1,478,132,568 |
| 2015 | 15,107,812,480 | 13,586,394,583 | 14,773,124 | 1,521,417,897 |
| 2016 | 15,491,960,826 | 13,929,315,213 | 18,679,904 | 1,562,645,613 |

Source: Energy Commission analysis

**Figure 28: California Diesel Fuel, Biodiesel, and Renewable Diesel Consumption (2003–2016)**




Source: Energy Commission analysis

**Table 3** contains finished diesel fuel consumption values between 2003 and 2016. The renewable and dyed components[31] already included as part of the finished diesel fuel numbers are shown separately. Biodiesel use elevated to 4.5 percent by volume during 2016, but renewable diesel fuel use took an even larger portion at 7 percent by volume. Although finished diesel consumption declined 15.9 percent between the peak in 2007 and the trough in 2009, the strong recovery from the recession and associated goods movement by truck and rail have pushed consumption back up by 15.5 percent between 2009 and 2016. Current levels are still 2.9 percent below the 2007 record consumption level of 3.8 billion gallons. The California State Board of Equalization (BOE) publishes diesel fuel sales figures, but these volumes include only taxable diesel fuel sales and exclude dyed diesel fuel distributions. The Energy Commission obtains dyed diesel figures from BOE to enable a more accurate estimate of total diesel fuel consumption, absent end use. Since 2004, these exempt sales have ranged between 19 and 24.8 percent of total consumption, a significant portion due to the extensive agricultural activity in the state.

**Table 3: California Diesel Fuel, Biodiesel, and Renewable Diesel Consumption (2003–2016)**

| Year | Finished Diesel Fuel Consumption Gallons | Dyed Diesel Consumption Gallons | Biodiesel Consumption Gallons | Renewable Diesel Consumption Gallons |
|---|---|---|---|---|
| 2003 | 3,296,529,763 | | 900,000 | |
| 2004 | 3,511,307,694 | 714,283,599 | 1,400,000 | |
| 2005 | 3,626,077,714 | 700,589,613 | 2,570,435 | |
| 2006 | 3,736,274,770 | 803,795,750 | 19,610,347 | |
| 2007 | 3,805,503,272 | 851,877,442 | 17,459,058 | |
| 2008 | 3,429,730,858 | 761,592,127 | 11,702,110 | |
| 2009 | 3,200,244,414 | 727,111,419 | 6,921,124 | |
| 2010 | 3,295,330,883 | 775,429,103 | 5,398,081 | 1,970,170 |
| 2011 | 3,263,535,007 | 790,354,407 | 18,211,031 | 1,803,488 |
| 2012 | 3,301,553,263 | 818,490,302 | 21,506,149 | 9,106,104 |
| 2013 | 3,478,458,889 | 844,315,866 | 78,817,509 | 135,781,842 |
| 2014 | 3,533,890,130 | 862,527,747 | 70,638,272 | 112,844,869 |
| 2015 | 3,650,173,276 | 895,996,443 | 164,973,794 | 165,155,935 |
| 2016 | 3,697,070,574 | 826,976,521 | 167,524,668 | 249,341,834 |

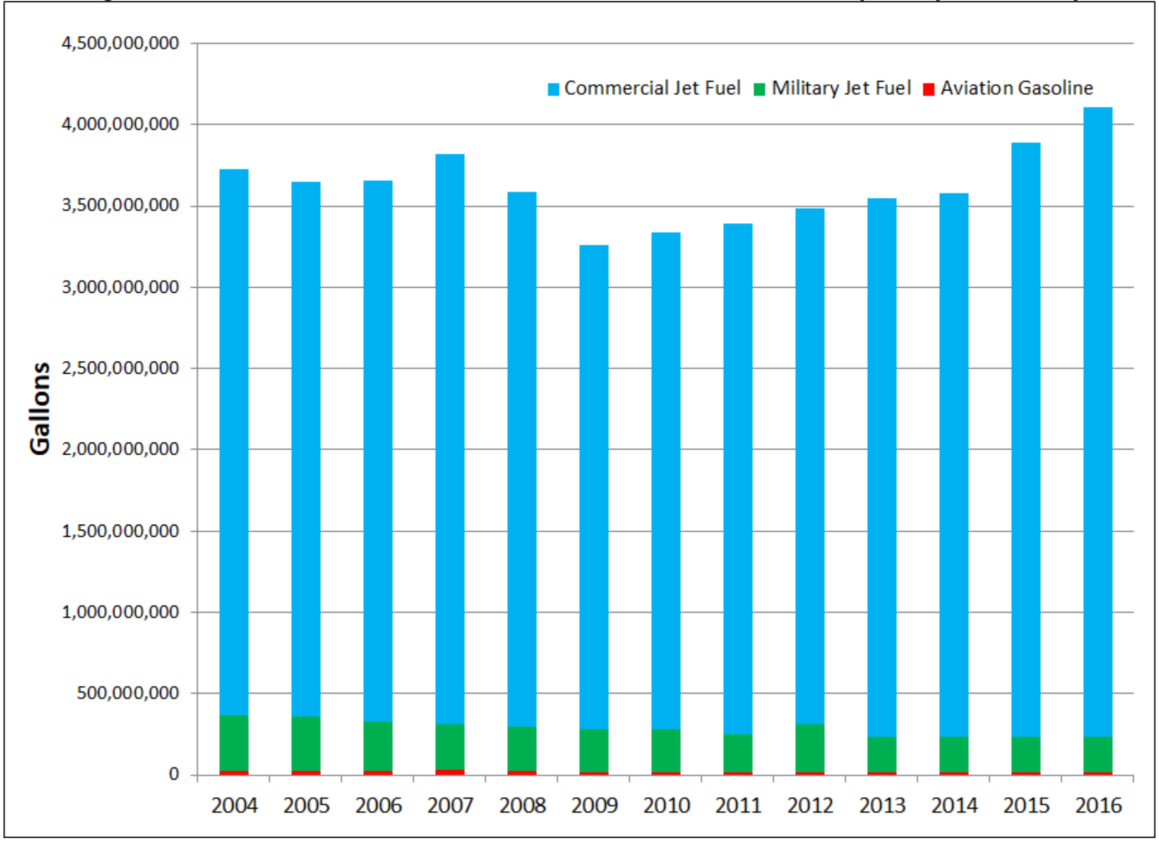
Source: Energy Commission analysis

31 *Dyed diesel fuel* is a term used for distribution (first sale) of diesel fuel that is intended for tax-exempt use such as agriculture, construction, mining, and other types of nonroad activity. Internal Revenue Service regulations control the nature of these requirements.

## Aviation Fuel

Commercial jet fuel is the second largest consumed traditional transportation fuel in California, accounting for 3.87 billion gallons during 2016 or 17 percent of total. Military jet fuel (218 million gallons) and aviation gasoline (16 million gallons) are also included for completeness of aviation fuel tracking. Military jet fuel is a special jet fuel formulation designed for military use, while aviation gasoline is a type of high-octane gasoline designed for airplane use. A breakdown of all aviation fuels is depicted in **Figure 29.**

**Figure 29: California Jet Fuels and Aviation Gasoline Consumption (2004–2016)**




Source: Energy Commission analysis

**Table 4** contains aviation fuel consumption values between 2004 and 2016.[32] Although commercial jet fuel consumption declined 15 percent between the peak in 2007 and the trough in 2009 (same pattern as diesel fuel), the strong recovery from the recession and associated rebound in air passengers and cargo have pushed consumption back up by 29.9 percent between 2009 and 2016 to a new record high of 3.87 billion gallons. The combined relative share of the other aviation fuels has been declining steadily from a high of almost 10 percent to less than 6 percent in 2016, primarily due to a drop in military jet fuel consumption.

32 Values for commercial and military jet fuel consumption between 2013 and 2016 should be considered preliminary estimates as the evaluation of the annual supply/demand balances has not yet been finalized.

**Table 4: California Aviation Fuel Consumption (2004-2016)**

| Year | Total Aviation Fuel Consumption Gallons | Commercial Jet Fuel Consumption Gallons | Military Jet Fuel Consumption Gallons | Aviation Gasoline Consumption Gallons |
|---|---|---|---|---|
| 2004 | 3,728,942,131 | 3,363,549,201 | 339,343,349 | 26,049,581 |
| 2005 | 3,645,885,614 | 3,284,023,013 | 336,774,630 | 25,087,971 |
| 2006 | 3,658,483,195 | 3,330,203,281 | 305,384,496 | 22,895,418 |
| 2007 | 3,822,301,789 | 3,509,109,565 | 285,390,657 | 27,801,567 |
| 2008 | 3,582,243,627 | 3,284,422,821 | 272,713,681 | 25,107,125 |
| 2009 | 3,259,096,327 | 2,978,928,324 | 260,519,367 | 19,648,636 |
| 2010 | 3,338,658,361 | 3,058,515,648 | 262,755,664 | 17,387,049 |
| 2011 | 3,393,599,114 | 3,142,276,329 | 234,600,600 | 16,722,185 |
| 2012 | 3,488,685,716 | 3,179,624,358 | 292,165,000 | 16,896,358 |
| 2013 | 3,548,947,536 | ***3,311,756,151*** | ***220,766,831*** | 16,424,554 |
| 2014 | 3,579,971,656 | ***3,348,260,144*** | ***215,802,947*** | 15,908,566 |
| 2015 | 3,889,817,983 | ***3,654,492,771*** | ***218,695,668*** | 16,629,545 |
| 2016 | 4,104,537,985 | ***3,870,372,741*** | ***218,421,815*** | 15,743,429 |
| | ***Preliminary Values*** | | | |

Source: Energy Commission analysis

## Gaseous Fuels

Besides the traditional transportation fuels, other types of fuels fill important roles, especially in medium- and heavy-duty vehicle applications. Propane and LNG are actually liquids when stored in fuel tanks onboard vehicles. CNG and hydrogen are routinely compressed and remain in gaseous phase. The natural gas-based fuels usually displace diesel fuel, whereas hydrogen transportation fuel usually displaces gasoline in light-duty vehicles. **Table 5** displays the various gaseous transportation fuel consumption values between 2003 and 2016; propane values for 2015 and 2016 are preliminary.

Gaseous transportation fuel consumption has grown as quickly as other types of renewable and traditional fuels over the last four years, but total consumption as measured in therms has more than doubled since 2004, increasing from 98 million therms in 2004 to 198 million therms in 2016.[33] A growing portion of natural gas use is being sourced from organic matter, referred to as *biomethane*. This renewable gas is an increasingly important source of credits under the CARB LCFS program as evidenced by the growth of its share of credits (about 7.5 percent for 2016), illustrated in **Figure 30**.[34]

33 LNG and CNG volumes are included in the total natural gas for transportation fuels calculation. Propane values are excluded since their sourcing is from refineries and natural gas liquid processing plants.

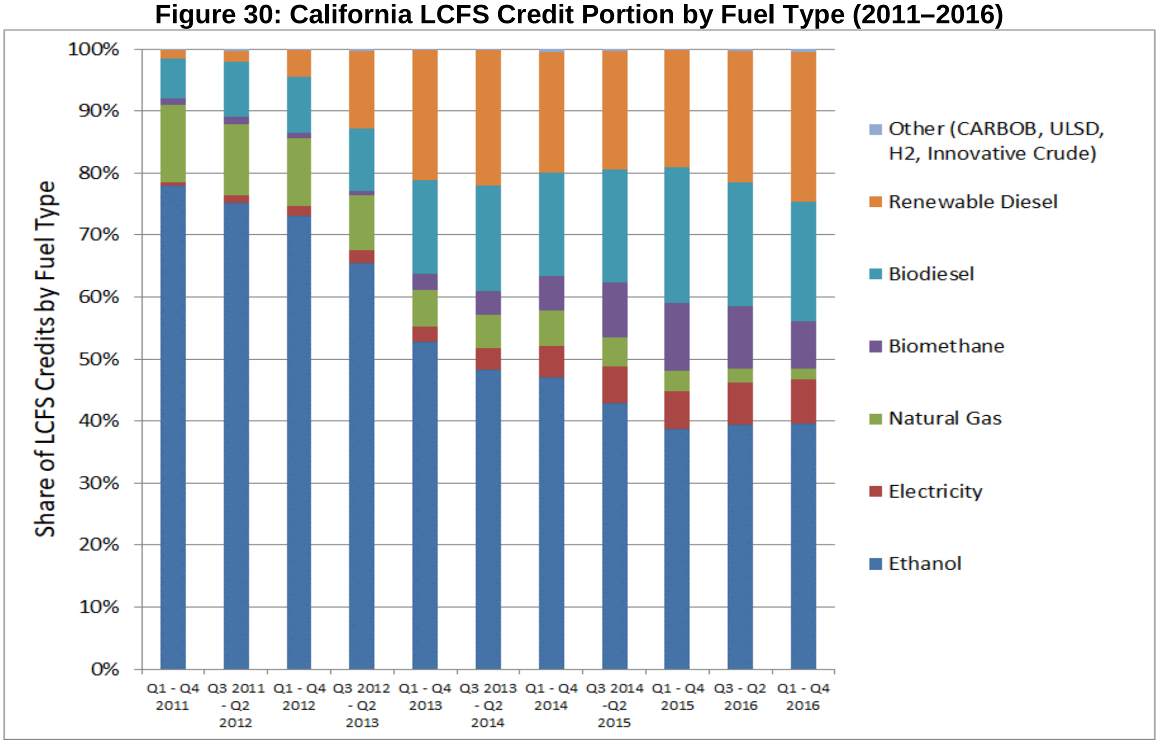
34 LCFS Reporting Tool Quarterly Summaries, LCFS Quarterly Data, California Air Resources Board, updated April 19, 2017. A link to the Excel spreadsheet is as follows: https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/media_request_040717.xlsx.

**Table 5: California Gaseous Fuel Consumption (2003–2016)**

| | LPG (Propane) Consumption Gallons | CNG Consumption Therms | LNG Consumption Gallons | Hydrogen Consumption Kilograms |
|---|---|---|---|---|
| 2003 | 18,455,500 | 64,686,479 | 27,970,031 | 728 |
| 2004 | 23,317,500 | 64,686,479 | 28,307,916 | 15,555 |
| 2005 | 22,999,500 | 77,007,713 | 28,645,800 | 9,275 |
| 2006 | 19,983,500 | 80,088,022 | 28,983,685 | 17,454 |
| 2007 | 18,316,000 | 86,248,639 | 22,400,000 | 19,987 |
| 2008 | 18,391,000 | 95,489,564 | 18,900,000 | 23,971 |
| 2009 | 22,861,067 | 98,569,873 | 29,635,453 | 38,292 |
| 2010 | 26,632,877 | 101,650,181 | 32,356,377 | 34,096 |
| 2011 | 29,139,991 | 104,730,490 | 35,487,647 | 52,179 |
| 2012 | 33,028,638 | 110,891,107 | 30,492,564 | 73,443 |
| 2013 | 34,755,459 | 113,971,416 | 31,868,353 | 66,276 |
| 2014 | 31,834,779 | 124,752,495 | 33,082,102 | 64,499 |
| 2015 | ***25,806,328*** | 126,292,650 | 34,000,572 | 62,708 |
| 2016 | ***5,793,698*** | 141,694,192 | 31,605,833 | 110,575 |
| | ***Preliminary Values*** | | | |

Source: Energy Commission analysis.

**Figure 30: California LCFS Credit Portion by Fuel Type (2011–2016)**

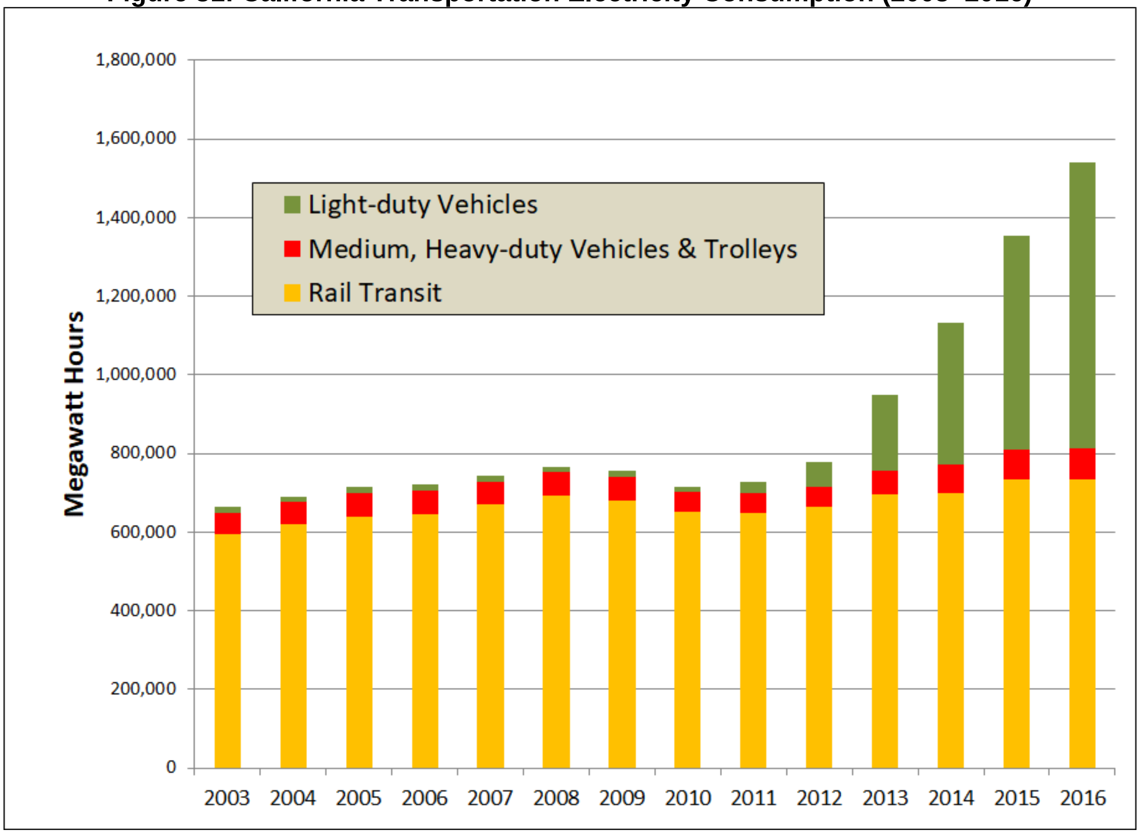



Source: California Air Resources Board.

## Transportation Electricity

Electricity is the final type of transportation fuel discussed in this section. Consumption of electricity for transportation purposes consists of electric vehicle charging and direct use by electric trolleys, light rail, and larger fixed rail transit operations, such as the Bay Area Rapid Transit system. Vehicles can be broken down by light-medium-and heavy-duty classes. **Figure 31** shows how total transportation electricity use has climbed from 664.5 gigawatt-hour (GWh) in 2003 to a near tripling of 1,500 GWh by 2016.

**Figure 31: California Transportation Electricity Consumption (2003–2016)**




Sources: Federal Transit Administration & Energy Commission analysis of DMV data.

As **Figure 31** shows, demand for transit-related and non-light-duty vehicles has been rather steady. The large increase of electricity consumption for transportation is a consequence of the growing number of battery electric and plug-in electric vehicles purchased in California from 62 thousand megawatt-hour (MWh) in 2012 to 727.0 thousand MWh by 2016, a 10-fold increase within four years. This category of end use represents 47.2 percent of total transportation electricity, only slightly less than the 47.6 percent used by rail during 2016. Medium-/heavy-duty vehicle and trolley use accounted for the remaining 5.2 percent. Growth in electricity consumption for light-duty vehicles is expected to continue rising and should easily become the largest share by 2017 because a disproportionately larger share of new U.S. light-duty electric vehicle sales are being delivered to California. For example, new vehicle registration in California for Tesla accounted for 17,615 cars during 2016, 44 percent of Tesla's national sales

(39,975 vehicles) during the same period.[35] **Table 6** contains the annual breakdown of California transportation electricity consumption since 2003.

**Table 6: California Transportation Electricity Consumption (2003–2016)**

| | Total Electricity Consumption MWh | LDV Consumption MWh | MD/HD & Trolleys Consumption MWh | Rail Transit Consumption MWh |
|---|---|---|---|---|
| 2003 | 664,512 | 17,057 | 51,597 | 595,858 |
| 2004 | 688,744 | 13,013 | 57,309 | 618,421 |
| 2005 | 714,373 | 15,044 | 60,699 | 638,631 |
| 2006 | 720,969 | 14,702 | 59,540 | 646,727 |
| 2007 | 741,970 | 13,821 | 58,959 | 669,190 |
| 2008 | 766,787 | 14,968 | 60,483 | 691,335 |
| 2009 | 756,853 | 16,090 | 61,621 | 679,143 |
| 2010 | 714,302 | 11,450 | 51,363 | 651,489 |
| 2011 | 726,542 | 27,750 | 50,794 | 647,998 |
| 2012 | 778,313 | 62,187 | 50,677 | 665,450 |
| 2013 | 948,886 | 192,037 | 59,675 | 697,174 |
| 2014 | 1,133,166 | 362,477 | 71,381 | 699,307 |
| 2015 | 1,354,796 | 544,405 | 77,727 | 732,665 |
| 2016 | ***1,540,159*** | 726,968 | 80,527 | ***732,665*** |
| | ***Preliminary Values*** | | | |

Source: Energy Commission analysis

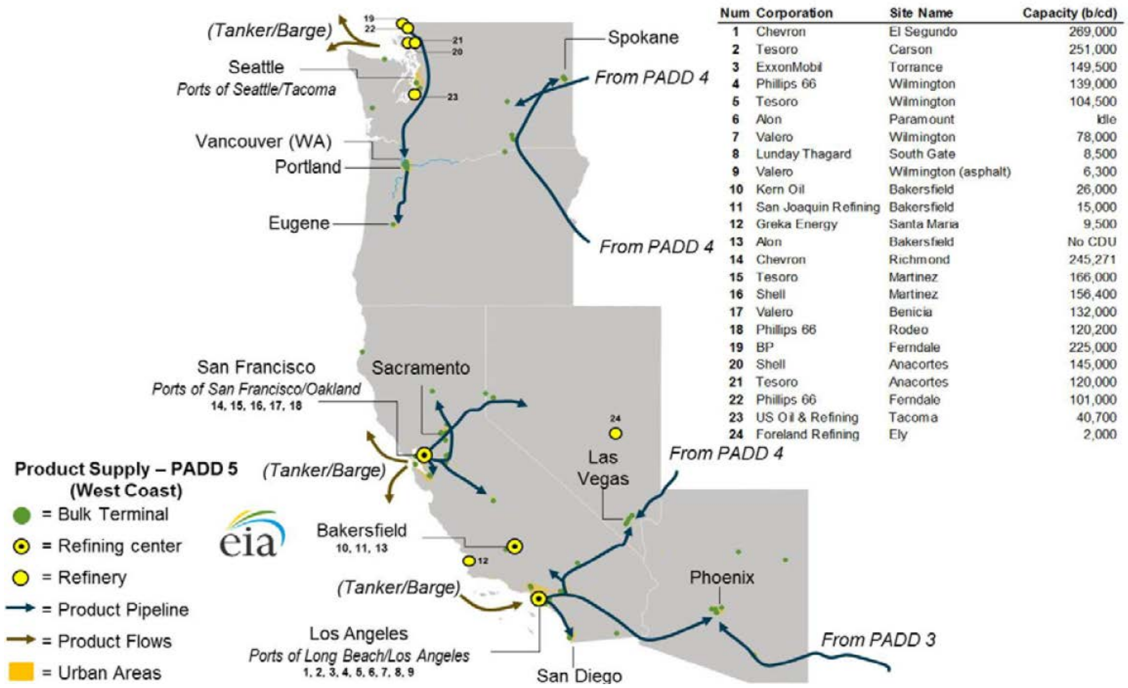
## California Transportation Fuel Product Movements

California's transportation fuel market is nearly self-sufficient, so supplies of gasoline and diesel fuel from outside California are not routinely needed to balance local refinery production with statewide demand. Pipelines connect California refining centers to distribution terminals in Nevada and Arizona, but these pipelines operate only in one direction—sending gasoline and other transportation fuels to these neighboring states. This larger market region is referred to as the *Petroleum Administrative for Defense Districts* or PADD 5. **Figure 32** shows the general location of California's refining centers and the associated proximity to water access (except for the Bakersfield area) to allow for receipts of crude oil, along with imports and exports of refined petroleum products and other feedstocks.

35 California new Tesla registrations are obtained from the *California Auto Outlook*, California New Car Dealers Association, Volume 13, Number 1, Released February 2017, page 3. A link to this publication is as follows: http://www.cncda.org/CMS/Pubs/CA%20Auto%20Outlook%204Q%202016.pdf.
National Tesla new vehicle sales figures are compiled from monthly reports generated by Motor Intelligence. A copy of their latest monthly new vehicle sales report may be accessed at http://www.motorintelligence.com/m_frameset.html.

The normally balanced nature of the California transportation fuel market is in stark contrast to other regions of the United States that are either significantly dependent on imports like the East Coast (PADD 1) or significant exporting regions such as the U.S. Gulf Coast (PADD 3). **Figure 33** illustrates the refining centers and refined product flows out of and into each of these regions.

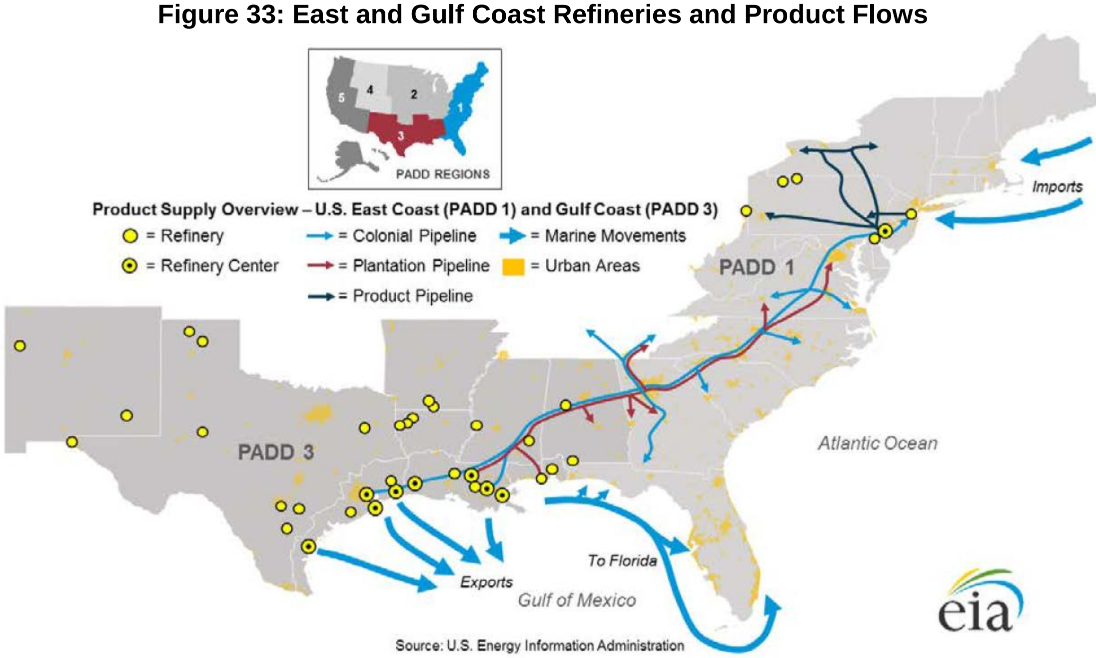
**Figure 32: PADD 5 Refineries and Product Flows**




| Num | Corporation | Site Name | Capacity (b/cd) |
|---|---|---|---|
| 1 | Chevron | El Segundo | 269,000 |
| 2 | Tesoro | Carson | 251,000 |
| 3 | ExxonMobil | Torrance | 149,500 |
| 4 | Phillips 66 | Wilmington | 139,000 |
| 5 | Tesoro | Wilmington | 104,500 |
| 6 | Alon | Paramount | Idle |
| 7 | Valero | Wilmington | 78,000 |
| 8 | Lunday Thagard | South Gate | 8,500 |
| 9 | Valero | Wilmington (asphalt) | 6,300 |
| 10 | Kern Oil | Bakersfield | 26,000 |
| 11 | San Joaquin Refining | Bakersfield | 15,000 |
| 12 | Greka Energy | Santa Maria | 9,500 |
| 13 | Alon | Bakersfield | No CDU |
| 14 | Chevron | Richmond | 245,271 |
| 15 | Tesoro | Martinez | 166,000 |
| 16 | Shell | Martinez | 156,400 |
| 17 | Valero | Benicia | 132,000 |
| 18 | Phillips 66 | Rodeo | 120,200 |
| 19 | BP | Ferndale | 225,000 |
| 20 | Shell | Anacortes | 145,000 |
| 21 | Tesoro | Anacortes | 120,000 |
| 22 | Phillips 66 | Ferndale | 101,000 |
| 23 | US Oil & Refining | Tacoma | 40,700 |
| 24 | Foreland Refining | Ely | 2,000 |

Source: U.S. EIA

**Figure 33: East and Gulf Coast Refineries and Product Flows**




Source: U.S. EIA

Although the Northeast United States has refining capacity, that region is still heavily dependent on fuel imported via pipelines from the Gulf Coast refineries and marine imports from foreign and domestic sources. During 2014, the East Coast consumed an average of 4.9 million BPD of transportation fuels but produced only 975,000 BPD, representing 20 percent of the region's supply. In contrast, the U.S. Gulf Coast consumed an average of 2,449,000 BPD of transportation fuels yet produced 7,494,000 BPD.[36] This means that exports of transportation fuels from that region were more than twice as large as all the transportation fuel consumed. The nature of the supply/demand imbalances help explain why transportation fuel price spikes in the Gulf Coast are rare compared to California, where nearly all of the state's transportation fuel consumption needs are met by production from refineries operating within the state. Further, the heavy dependence of pipeline-sourced supply from the Gulf Coast to the Northeast means that pipeline operational problems can result in price spikes for the Northeast unrelated to any unplanned refinery outages.

## California Transportation Fuel Flows

Refinery outages have been blamed for California gasoline price spikes in both 2012 and 2015. This is a result of both Northern and Southern California's refinery hubs' isolation from the rest of the nation. The first point of resupply for each refinery hub in a shortage is the opposite hub. If supplies are needed beyond what could be provided within California, the next closest production point is used to obtain needed fuel, in this case, the Pacific Northwest. With the Pacific Northwest now more balanced with little slack production available, international sources of transportation fuels are more important than ever in responding to temporary California supply shortages.

**Figure 34** shows the sequence of steps required to move transportation fuels from point of production or import to final point of retail distribution. The majority of gasoline and diesel fuel consumed in California is transported from refineries via petroleum product pipelines to nearly 60 distribution terminals scattered throughout the state. Multiple types of transportation fuels are pumped through the same pipelines through a "batch" sequencing process that keeps steady pressure within the pipeline to diminish the mixing between batches of different transportation fuels (**Figure 35**).[37]

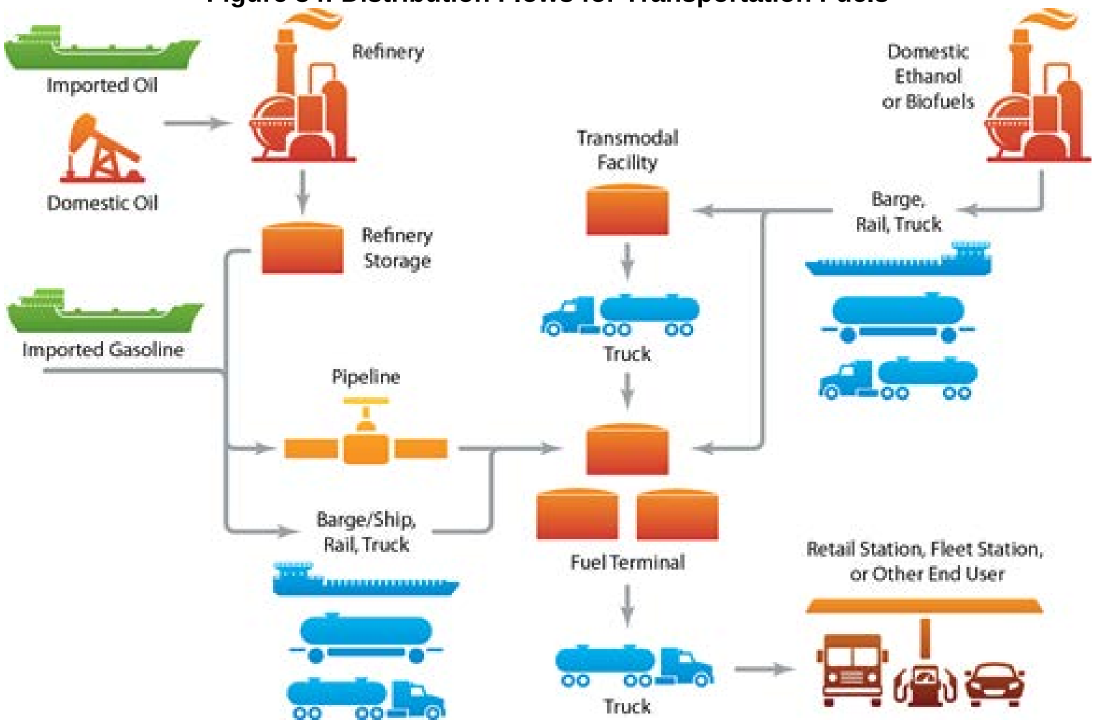
Nearly all commercial jet fuel is also distributed via petroleum product pipelines, being directly delivered to storage facilities at major airports. Most of this pipeline distribution capacity is owned and operated by Kinder Morgan, a common carrier operator who does not own any of the transportation fuels it ships; rather it charges a fee per barrel based on approved tariff rates, along with storage and distribution terminal throughput costs.

---

36 East and Gulf Coast Transportation Fuels Markets, U.S. EIA, February 2016, page 3. A link to this report is as follows: https://www.eia.gov/analysis/transportationfuels/padd1n3/pdf/transportation_fuels_padd1n3.pdf.

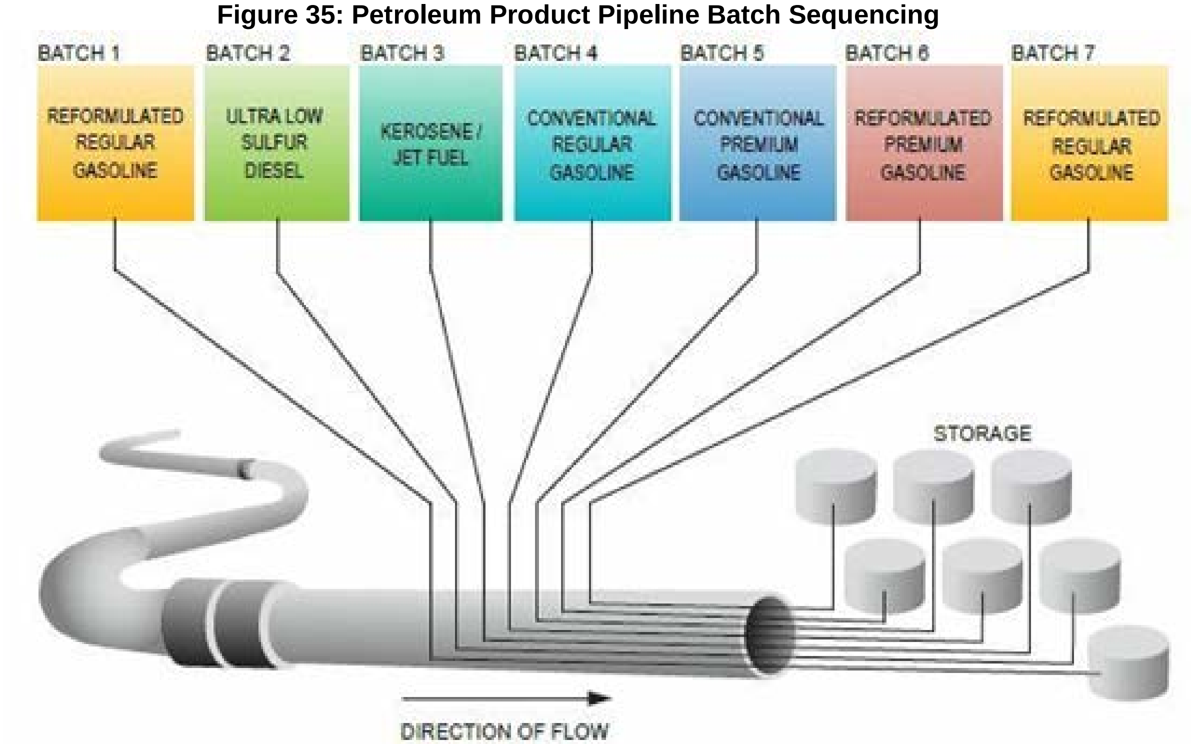
37 The mixtures of different fuels that occur during pipeline transport are referred to as "transmix" and temporarily stored in a separate tank at each distribution terminal before being trucked back to refineries for reprocessing. In some instances, the transmix is sent in a batch in the pipeline system to select locations that have their own transmix processing equipment.

**Figure 34: Distribution Flows for Transportation Fuels**




Source: Alternative Fuels Data Center

**Figure 35: Petroleum Product Pipeline Batch Sequencing**




Source: Energyskeptic.com

Distribution terminals receive transportation fuels via petroleum product pipelines from several suppliers that are typically commingled together in the same community storage tanks for like types of fuel, due to a lack of additional storage tanks to keep every shipper's fuel delivery segregated. Thus, gasoline delivered to a branded service station may not have originated from the refinery associated with that station's brand but is probably a mixture of various gasolines from more than one refining facility. The "difference" between branded retail station gasoline is the type of proprietary additive packages used when the gasoline is loaded into a tanker truck before delivery to a service station. As an example, gasoline destined for a Chevron retail station would be required to contain Chevron's proprietary additive Techron.[38] Each major refiner in California has its proprietary additive packages used for fuel at its branded stations, regardless of who owns the retail station. Gasoline sold at unbranded retail stations is still required to contain a generic additive package that meets detergent and deposit control minimum standards.

Distribution terminals are also the point at which renewable fuels (ethanol, biodiesel, and renewable diesel fuel) are combined with petroleum-based fuels (gasoline and diesel fuel) as the tanker truck is loaded. These "finished" transportation fuels are then delivered to wholesale facilities, private distribution sites (card-locks), and retail stations (truck stops and service stations).

### Regional Pipeline Systems

**Figure 36** depicts the extent of Kinder Morgan's Northern California operations that enable pipeline shipments from Bay Area refineries to Chico (farthest north extension), Fresno (southernmost extension), greater Bay Area locations, and Nevada distribution terminals at Reno and Fallon Naval Air Station. The pipeline segment off the Chico line is no longer operational, along with the segment from the Alon Bakersfield refinery to the Fresno distribution terminal (since the Alon refinery is idle).

Refiners also operate limited petroleum product pipelines that are usually proprietary for shipment of a portion of their transportation fuel production to one or two of their proprietary distribution terminals. The refiner exception to this limited proprietary system would be Chevron, which has a more significant petroleum product pipeline distribution network compared to other refining companies operating in California. **Figure 37** shows the extent of Kinder Morgan's southwestern pipeline system operations that enable exports of transportation fuels from Southern California refineries to distribution terminals in Southern Nevada (Las Vegas) and Central Arizona (Phoenix). Arizona marketers are also able to receive shipments from refining locations in West Texas and New Mexico.

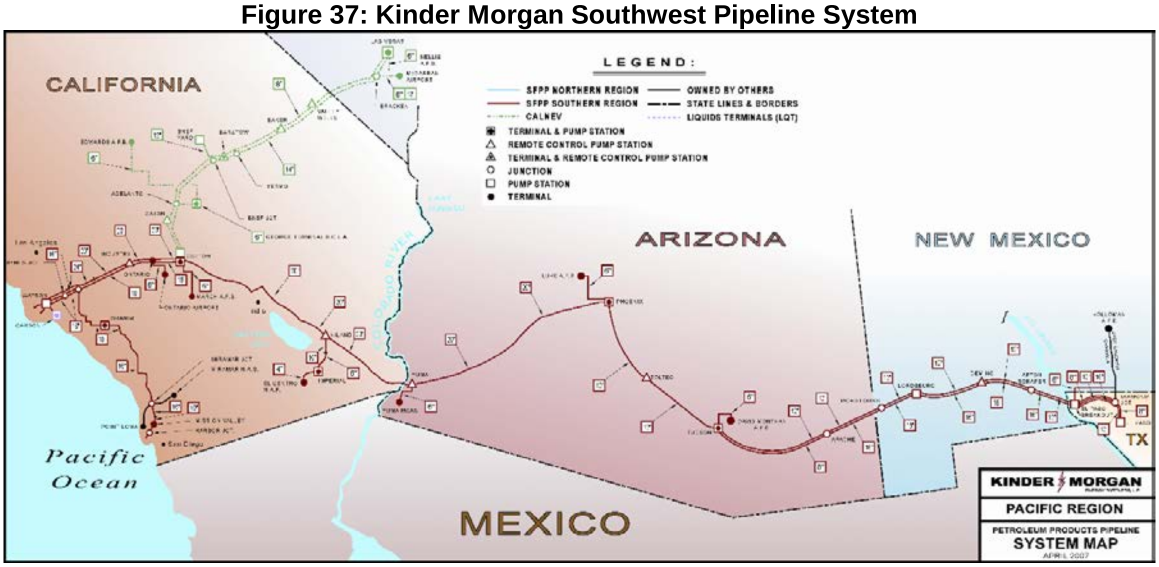
---

38 A description of deposit control additive development history and function is contained in *Motor Gasolines Technical Review*, Chevron, 2009, pages 77-82. A link to the report is as follows: https://www.chevron.com/-/media/chevron/operations/documents/motor-gas-tech-review.pdf.

**Figure 36: Kinder Morgan Northern California Pipeline System**


Source: Energy Commission modification to Kinder Morgan system map

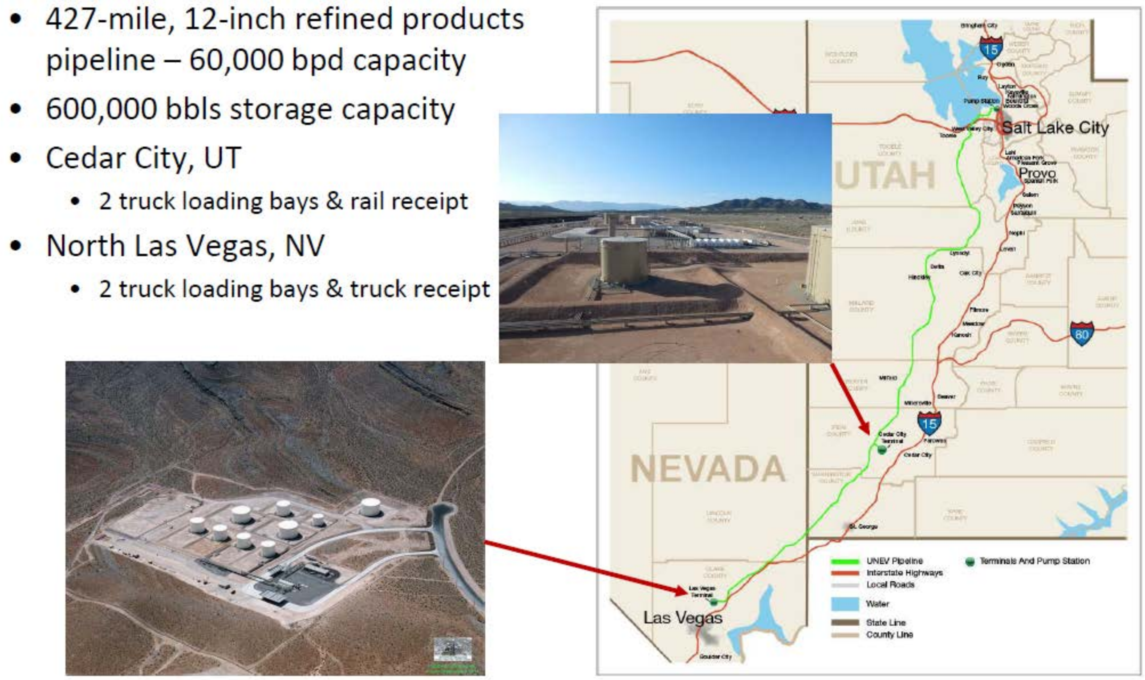
**Figure 37: Kinder Morgan Southwest Pipeline System**




Source: Energy Commission modification to Kinder Morgan system map

These pipeline distribution systems allow Nevada to receive nearly 85 percent of its transportation fuels from California, and Arizona to receive roughly 45 percent of its supply from Southern California refineries. Recently, the portion of supply provided to Nevada by California refineries has lessened with operation of the UNEV petroleum product pipeline system that provides fuel from refineries in Salt Lake City, Utah (**Figure 38**).

**Figure 38: UNEV Pipeline System**



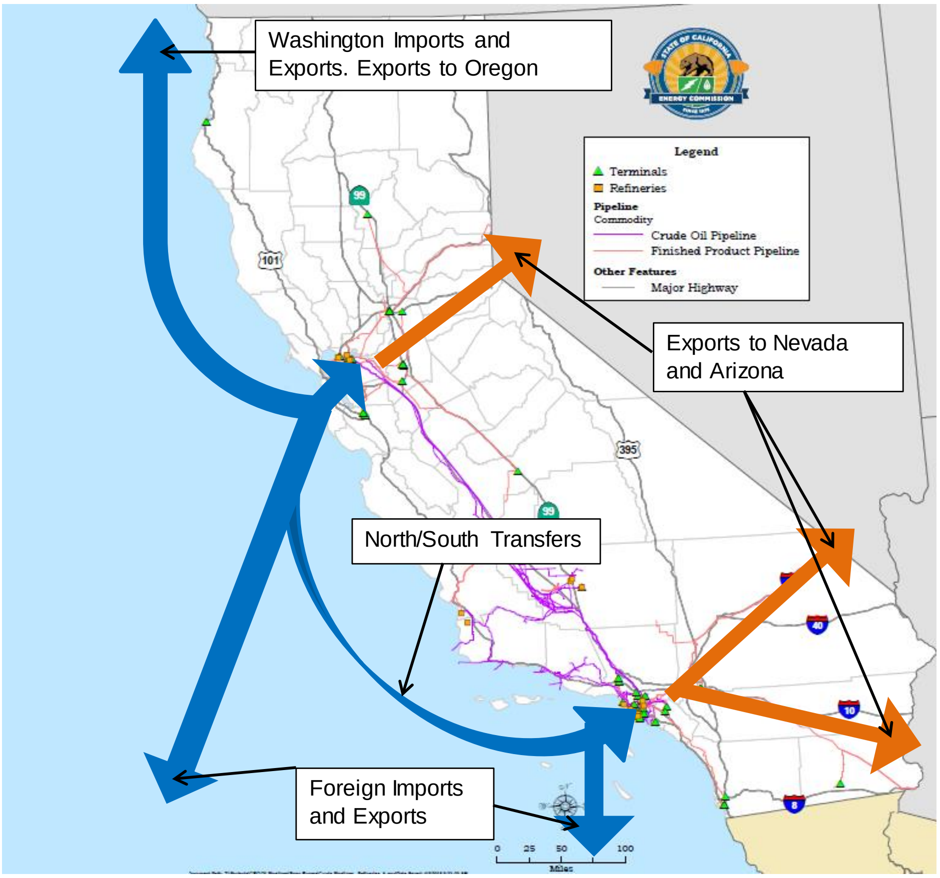

Source: Holly Energy Partners

## Gasoline Flows—Imports, Exports, and Intrastate Movements

Finished product made from crude oil entering California leaves the Northern and Southern California refinery hubs in all directions. **Figure 39** displays a map of California's petroleum product infrastructure that contains arrows denoting both marine movements of finished product (in blue) and pipeline movements of product (orange).

Transportation Fuels Data Unit staff tracks finished product movement both entering and leaving California. These finished product movements include marine foreign imports and exports of finished products and blendstocks; marine interstate imports and exports of finished products; marine inter-California transfers of finished products and blendstocks; and pipeline exports of product. As seen in **Figure 39**, Southern California's pipeline exports support both the Southern Nevada/Las Vegas and Western Arizona/Phoenix markets. Northern California pipeline exports to northern Nevada support Reno and its surrounding communities.

**Figure 39: California's Petroleum Infrastructure and Finished Product Movements Corridors**

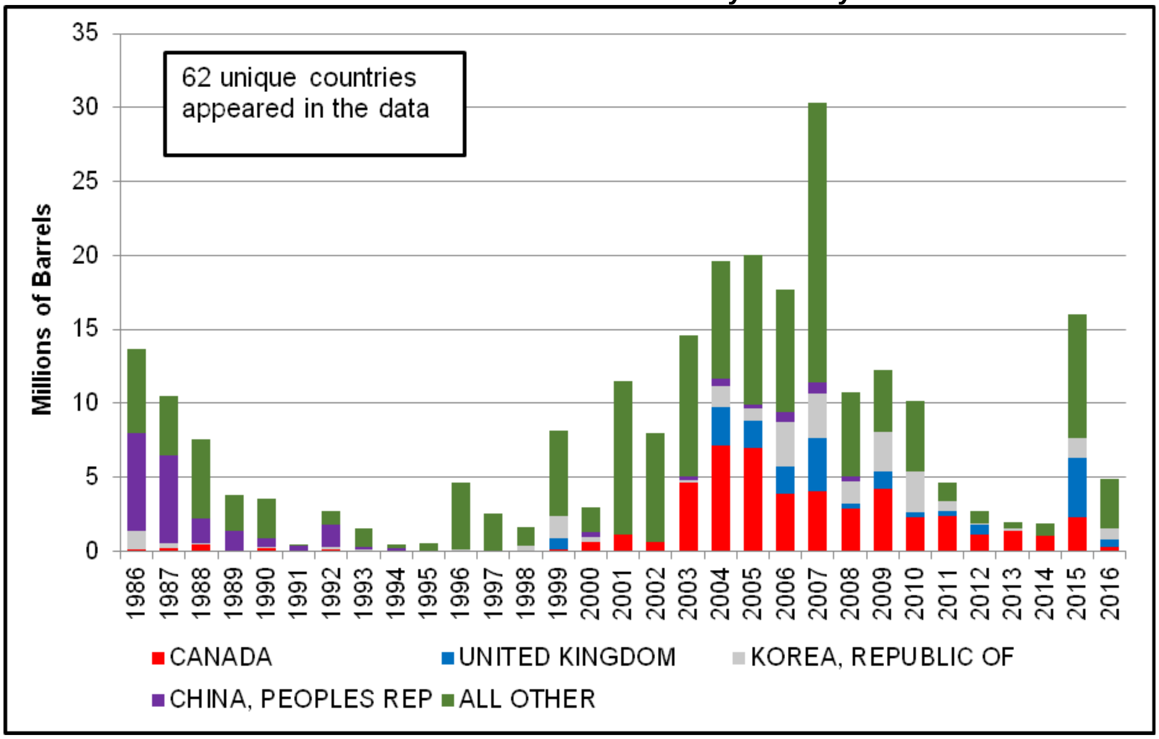



Source: Energy Commission

Marine interstate exports from both Northern and Southern California tend to be delivered to the states of Washington and Oregon, with occasional exports to Hawaii, Alaska, and Texas. At the same time, California will import finished products and blendstocks from the refineries in Washington, Hawaii, and Texas to meet local supply/demand balance needs. Marine foreign exports of finished products and blendstocks are typically shipped to Canada and Mexico, but exports have gone to as far as Japan, Chile, and Belgium.

Since 1986, California has also imported finished gasoline and gasoline blendstocks from 62 different foreign countries, indicating that importers will obtain product from wherever they can obtain the best price (**Figure 40**). California's main source of foreign gasoline product imports since 2000 has been Canada, with California importing a total of 46.88 million barrels of gasoline and gasoline blendstocks. Most imports occurred between 2003 and 2010, averaging 4.5 million barrels of gasoline product per year from Canada. The next most common foreign sources of gasoline and gasoline blendstocks imports were from the United Kingdom and South Korea. Each provided 9.5 percent of gasoline imports over the 2000 to 2016 period, varying amounts of imports depending on world market conditions. Before 2000, California's largest source of gasoline imports came from China, which from 1986 to 1999 accounted for 30 percent of all gasoline imports at 18.4 million barrels.

**Figure 40: Annual Foreign Imported Gasoline and Gasoline Blendstocks Volumes by Country**

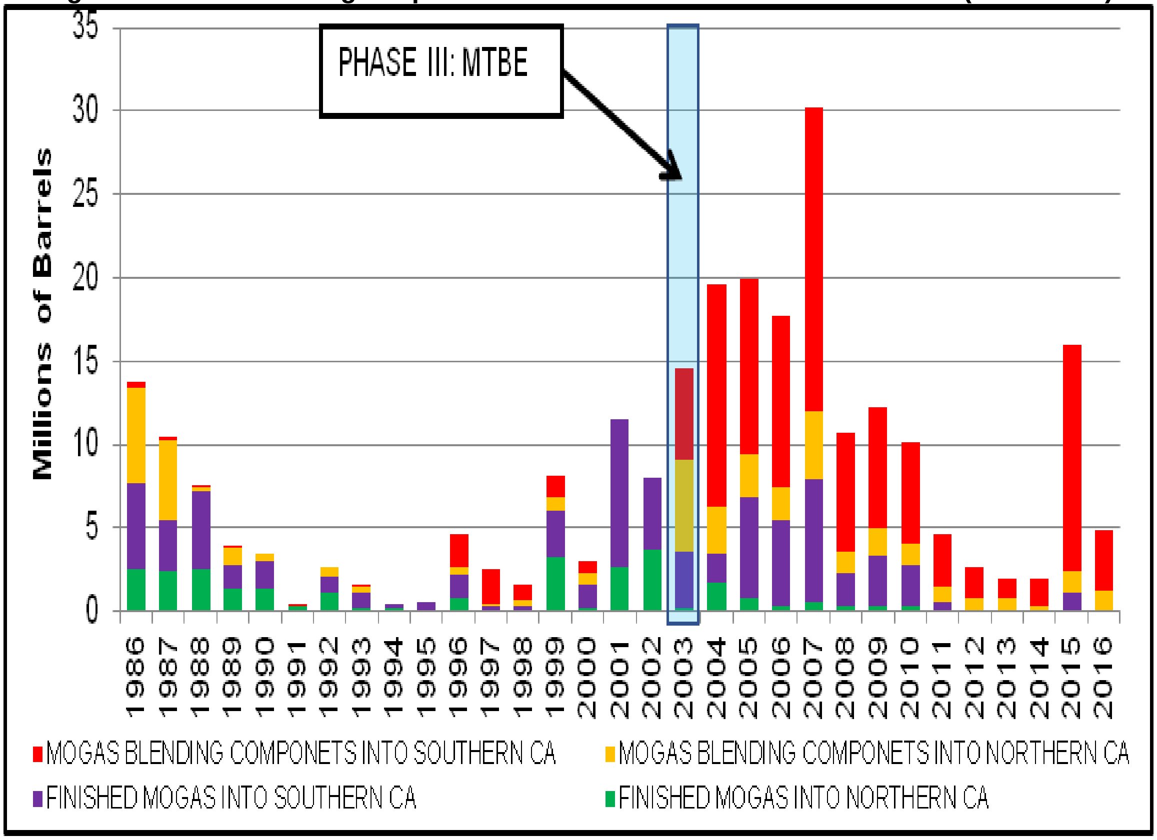



Source: U.S. EIA

Since California gasoline specifications have become more stringent, the likelihood of finished product being imported from a foreign location is noticeably less. However, refiners create finished gasoline from numerous types of gasoline-blending components that are refined from crude oil. California's more stringent gasoline standards do not prevent refiners from importing key blending components that enable them to increase their gasoline "production" to offset temporary losses in output due to unplanned refinery outages.

**Figure 41** shows U.S. EIA information on foreign imports into California of finished gasoline also known as Motor Gasoline (MOGAS) and gasoline blendstocks. Red and yellow portions of the chart denote foreign-sourced gasoline blending component import volumes into Southern and Northern California respectively. Purple and green portions represent foreign-sourced finished gasoline import volumes into Southern and Northern California respectively. Since the methyl tert-butyl ether (MTBE) phaseout that took effect at the beginning of 2003, imports from foreign sources have been primarily blending components, averaging 83 percent combined gasoline and gasoline blendstock import totals by volume. The lowest percentage of total foreign gasoline imports that include blending components have been since 2003 occurred in 2005 at 65 percent of foreign gasoline imports. Since 2010, the highest percentage that finished gasoline has been of foreign imports occurred in that same year at 27 percent, since then averaging only 5 percent a year. Before the MTBE phaseout, foreign-sourced gasoline imports were predominantly finished gasolines, averaging a little over 70 percent of the gasoline product imported into California from foreign sources.

**Figure 41: Annual Foreign Imported Gasoline and Gasoline Blendstocks (1986–2016)**

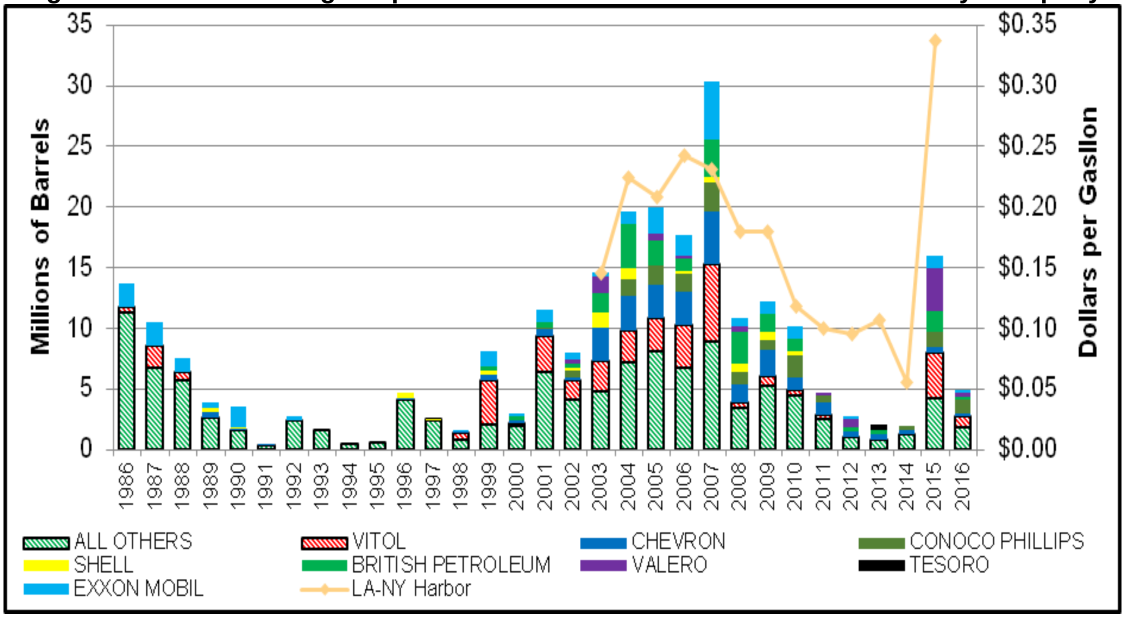



Source: U.S. EIA

Like the foreign sources of gasoline product, the importers of record for gasoline product are many and varied. Analyzing U.S. EIA company level import information shows that there have been at least 55 companies that have imported gasoline product into California since 1986. **Figure 42** shows annual volumes of imported gasoline by importer of record. On average, the refining companies displayed here typically account for 33 percent of the imports entering the state over the 1986 to 2016 period. That average percentage has increased in recent years, to 48 percent for the 2010 to 2016 time frame, signaling a reduction in the number of nonvertically integrated importers in California. These nonvertically integrated import companies (such as Vitol) import product into California that is later sold directly on either the spot market or directly to a refiner. From 1986 to 2016, Vitol has imported at least 36 million barrels of gasoline into California from foreign ports, accounting for roughly 15 percent of all foreign gasoline imports over that period. In recent years, the reduction of these types of companies participating in the California import market is a signal of reduced liquidity in both the California import and spot gasoline markets. This reduced liquidity was identified by the Energy Commission's Petroleum Market Advisory Committee as a possible source of price volatility.[39]

39 Petroleum Market Advisory Committee meeting transcripts and materials found at http://www.energy.ca.gov/assessments/petroleum_market/.

**Figure 42: Annual Foreign Imported Gasoline and Gasoline Blendstocks by Company**




Source: U.S. EIA

What is also seen in **Figure 42** is that imports of gasoline into California are highly responsive to the difference between the spot gasoline market price in California versus other ports. The light-yellow line is the difference between the Los Angeles spot market price for reformulated blendstock for oxygenate blending (RBOB) minus the spot market price for conventional gasoline in New York Harbor. As the differential between the two prices increases, foreign imports into California increase, especially from nonrefining companies. Higher local prices relative to an international benchmark price like the New York Harbor enable more expensive foreign imports to be delivered economically to California. These higher annual average spot price differences are usually a reflection of more significant unplanned refinery outages that decrease local production. Gasoline imports on an annual basis mirror declines or increases in demand. As the differential decreases, the opposite effect occurs and foreign imports decrease as the arbitrage window closes and importing gasoline becomes uneconomical. Also seen in **Figure 42**, 2015 as a year required special attention and will be discussed in detail later in the chapter.

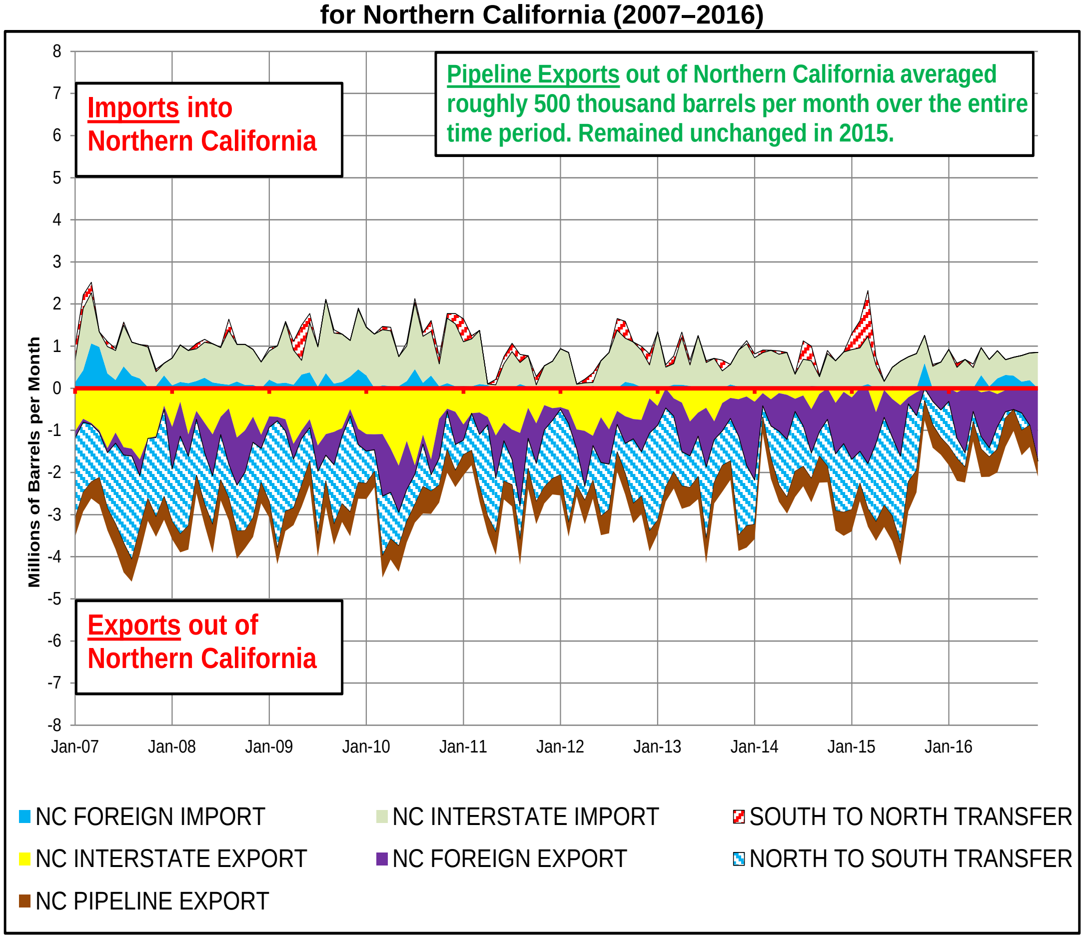
While U.S. EIA company level imports provide detailed information on imports into the United States from foreign ports, they contain no information on interstate and intrastate transfers of products or information on the foreign exporting of product. To get the complete picture of California finished product movements, staff analyzes CEC-M700 reports,[40] State Lands Commission marine shipping records, and other subscription service information. These sources provide insights into flows into and out of the state for petroleum-based products, but they neither provide the additional product detail nor categorize products similarly to U.S. EIA information. This prevents detailed assessments of the difference between finished gasoline and gasoline blendstocks, as well as differences between California specification gasoline and other

40 CEC-M700 *California Imports, Exports, and Intrastate Movements Monthly Report* is a monthly report mandated to be provided to the Energy Commission by all importers and exporters of petroleum fuel operating within California.

gasoline specifications. Staff does attempt to reconcile all the listed data sources with each other shipment by shipment, and when all gasoline specifications and blendstocks are grouped together sources, they do tend to agree, with some sources capturing movements missed by others.

**Figure 43** shows the Energy Commission gross[41] assessment of monthly gasoline (both finished and blendstocks) imports and exports out of the Northern California refinery hub area from January 2007 to December 2016. Imports are shown as positive values stacked upon each other in the top half of the **Figure 43**. Exports are shown as negative values stacked upon each other in the bottom half of the **Figure 43**. Since **Figure 43** represents in-and-out flows of gasoline in the Northern California refinery hub, transfers from Southern California to Northern California are shown as imports on the top half of **Figure 44**. Transfers from Northern California to Southern California are shown as exports at the bottom.

**Figure 43: Monthly Gross Gasoline and Gasoline Blendstocks Product Movements for Northern California (2007–2016)**




Source: Energy Commission

Foreign imports into Northern California (solid blue area) and Southern-to-Northern California movements (striped red area) are rare when it comes to gasoline product movements. The bulk of imported gasoline coming into Northern California is from other U.S. ports (yellow area), mostly

41 "Gross" refers to the total amount before anything is deducted.

from Washington. Overall, imported gasoline volume into Northern California has been declining slightly, standing at 760,000 barrels per month for 2016.

Continuing the inspection of **Figure 43**, export volumes out of Northern California appear to be greater than imports. Most of these gasoline export volumes are transferred to Southern California (blue striped area). This Northern-to-Southern California flow averaged 1.16 million barrels per month of gasoline leaving Northern California for the displayed period. It is unclear whether the 2016 decrease is a temporary response or a signal for reduced movements in the near future. Pipeline shipments leaving Northern California (brown area at the bottom) for the Northern Nevada area were also regular, averaging 500,000 barrels per month for the entire period and total a small portion of Northern California's export activity.

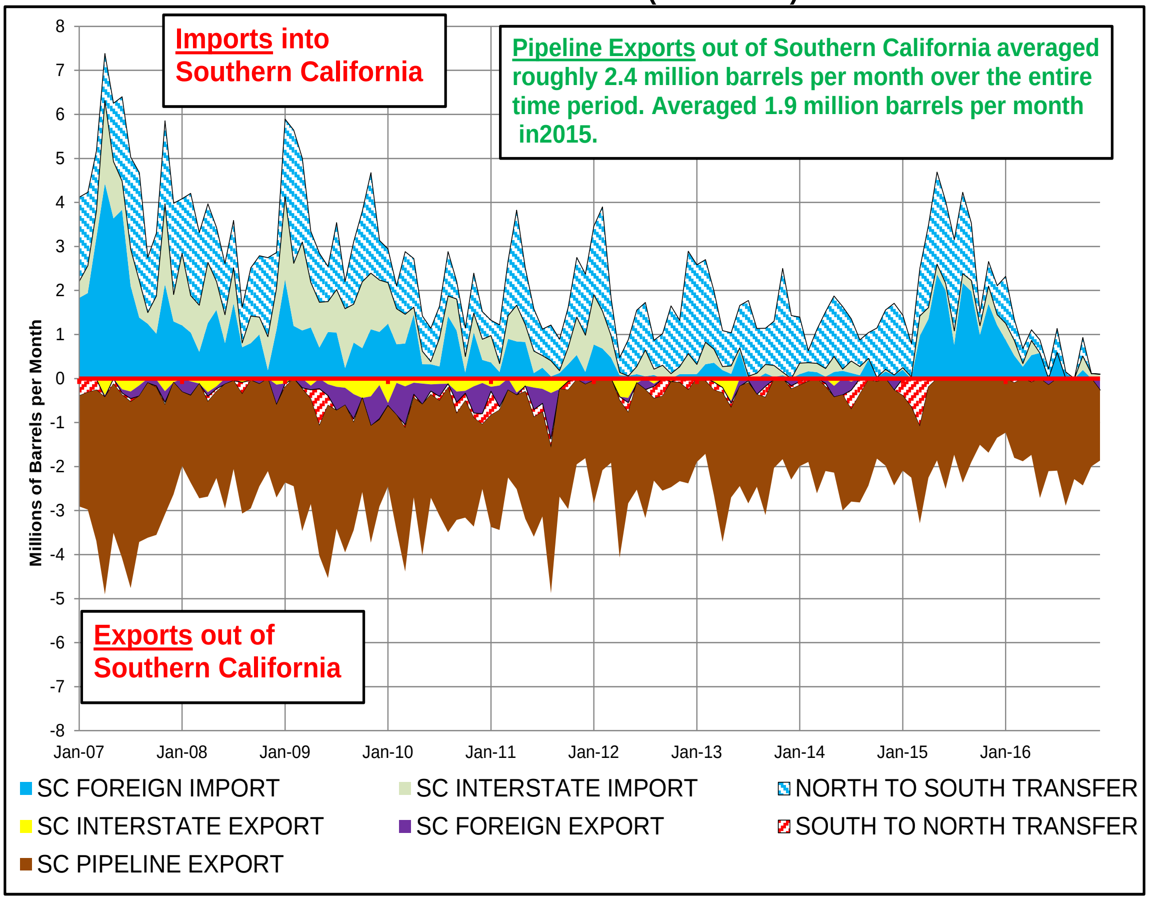
An export trend that did seem sustained was movement of gasoline out of Northern California to other non-Californian U.S. ports (yellow area). These interstate exports are clearly declining, averaging 955,000 barrels per month in exports for the 2007 to 2011 period but falling to 301,000 barrels per month from 2012 to 2016. A possible explanation is that shipments to Portland, Oregon, have been declining as Washington State refiners increase deliveries to Portland. These deliveries can occur through the Olympic Pipeline at less cost when compared to marine shipments from Northern California.

While these domestic exports of product out of Northern California are falling, it appears that Northern California refiners and gasoline shippers are still sending a portion of that product to foreign locations (purple area). Foreign exports of product averaged 502,000 barrels per month for the 2007 to 2011 period and increased to 802,000 barrels per month for the 2012 to 2016 period. This increase in export volume to foreign source accounts for roughly half of the 650,000 barrels per month decrease in interstate exports. With the other export flows maintaining similar trends, it appears Northern California is trending toward net balanced over the 2007 to 2016 period, a trend seen in **Figure 45**.

**Figure 44** shows the Energy Commission gross assessment of monthly gasoline imports into and exports out of the Southern California refinery hub area from January 2007 to December 2016. Using the same color scheme and format as **Figure 43**, **Figure 44** displays the magnitude of import and export volumes for Southern California, with transfers from Southern California to Northern California now showing as exports on the bottom half of **Figure 44.** Transfers from Northern California to Southern California are shown as imports at the top.

When compared to Northern California, movements of gasoline into and out of Southern California are noticeably greater. Southern California has regularly moved roughly 2 million barrels per month of gasoline out of the state in pipelines supporting the markets of southern Nevada and western Arizona (brown area at the bottom). A temporary drop in pipeline exports occurred in 2015, which is attributed to the loss of gasoline-producing process equipment at the Torrance refinery between February 2015 and July 2016. Even with the drop in exports, pipeline movements of gasoline out of the state are the largest portion of exports out of Southern California.

**Figure 44: Monthly Gross Gasoline and Gasoline Blendstocks Product Movements for Southern California (2007–2016)**




Source: Energy Commission

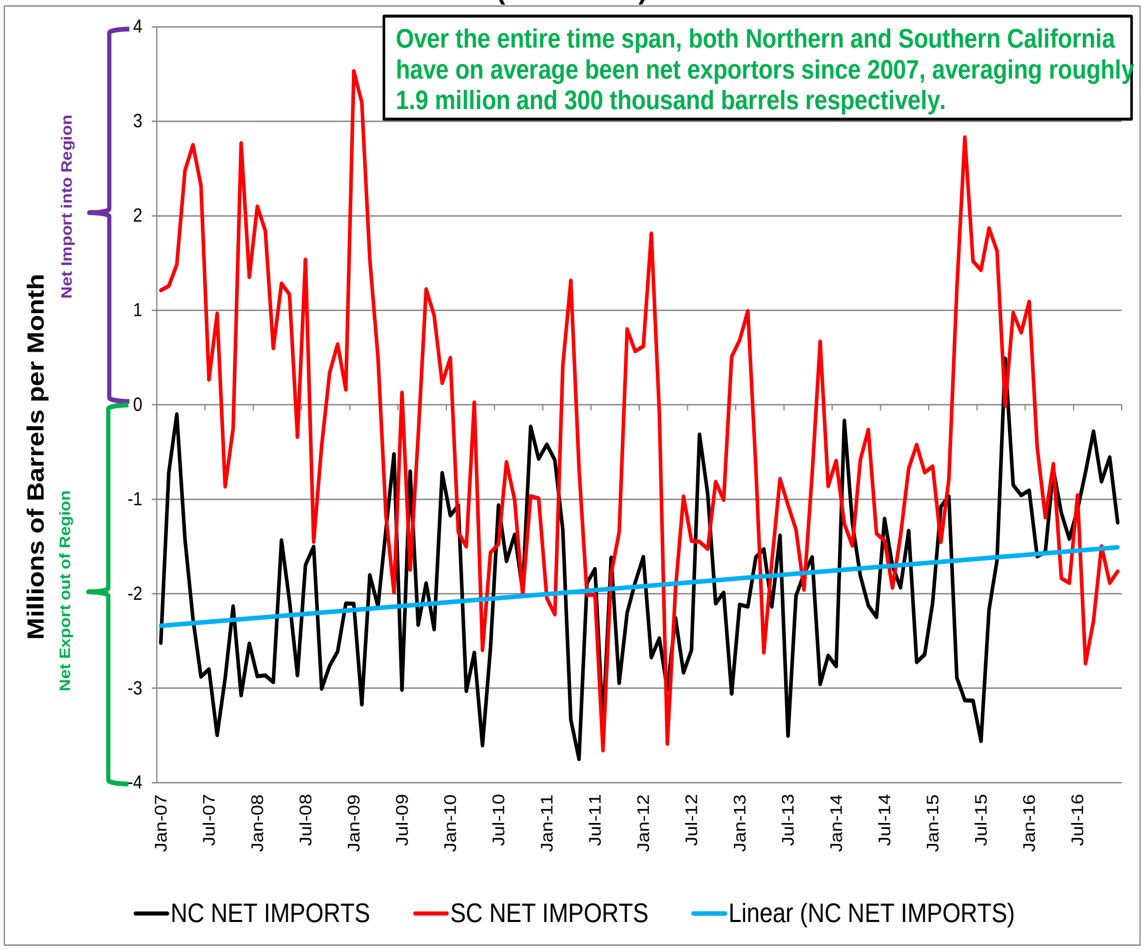
While pipeline exports are noticeably large, other exports leaving the area are conversely small. On average for the entire displayed period, nonpipeline exports averaged only 300,000 barrels per month, roughly one-eighth of the average pipeline export of 2.4 million barrels per month for the same period. These nonpipeline exports appear to be declining. From 2007 to 2011, they averaged 470,000 barrels per month, while from 2012 to 2016 they averaged only 185,000 barrels per month. In 2015, Energy Commission analysis showed no marine exports from Southern California to either another U.S. port or foreign destination. Transfers from Southern to Northern California occurred in January, February, March, and April of 2015 for a total of 2.3 million barrels, likely to help balance the Northern California market in the wake of Tesoro's Golden Eagle Refinery in Martinez delaying its 2015 restart due to labor issues.

Marine gasoline imports (solid blue and green areas) into Southern California far outpace marine exports. Northern-to-Southern California transfers averaged roughly 1.16 million barrels per month during the displayed period, which is equal to roughly half of Southern California's pipeline exports. Southern California is also a larger importer of foreign produced gasoline and blendstocks, a movement that appears to be slowing. From 2007 to 2011, on average, Southern California imported 1.1 million barrels per month of gasoline, while from 2012 to 2016 the average was only 423,000 barrels per month. Even that 2012 to 2016 average may be greatly overstated, as Southern California averaged 1.3 million barrels per month of foreign imports in 2015 due to the Torrance refinery outage, but averaged only 298,000 barrels per month the following year (2016), with the return of the Torrance refinery on July 2016. Interstate imports appear to be decreasing as well. From 2007 to 2011, Southern California averaged 792,000 barrels per month in domestic imports, but that has fallen to an average of 214,000 barrels per month for 2012 to 2016. Domestic imports did pick up in 2015, but decreased in 2016 to 138,000 barrels per month.

Looking at the gross import-export accounting of **Figure 43** and **Figure 44** the question is whether these two refinery centers are either net importer or net exporter. **Figure 45** displays the results of combining the positive import and negative export flows for both the Northern (black line) and Southern (red line) California. Northern California has been a constant net exporter of product during every month of the displayed period except October 2015. On average, Northern California was a net exporter of 1.9 million barrels of gasoline per month. This trend appears to be lessening, likely influenced by a resurgence of gasoline demand between 2012 and 2016. In **Figure 45**, the blue line indicates the linear trend of these monthly data for the Northern California net import line. This blue line is clearly moving up within the chart, trending to the net-balanced midpoint line. While in 2016 Northern California still averaged 1 million barrels per month of net exports, this is roughly a 50 percent decrease from the full period average.

Southern California's net situation is not so clear. From 2007 to 2011, this refinery center was roughly net-balanced, averaging 50,000 barrels of net imports per month into the area. But from 2010 to 2014, Southern California appears to start becoming a net exporter of product, averaging 959,000 barrels per month of net exports. With the Torrance refinery issues in 2015, Southern California returned to being a net importer, averaging 778,000 barrels per month of net imports. This change in net relationship was soon reversed as, in 2016, Southern California once again became a net exporter of product, averaging 1.34 million barrels per month in net exports for the year.

**Figure 45: Monthly Net Gasoline and Gasoline Blendstocks Regional Imports (2007–2016)**



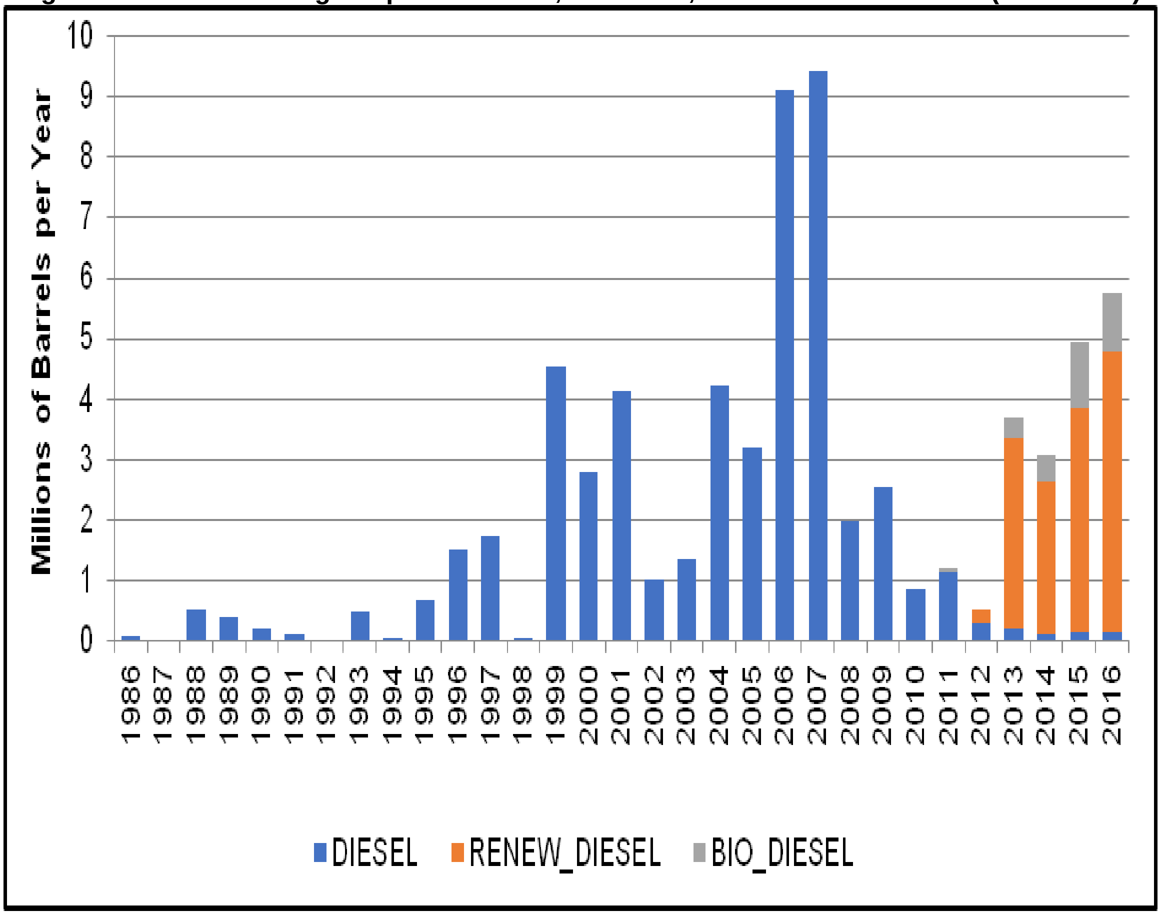

Source: Energy Commission.

## Diesel Flows—Imports, Exports, and Intrastate Movements

Finished diesel product follows a similar shipment flow pattern to that of gasoline, just not in the same quantities. Unlike gasoline, diesel does not have blending components shipments to account for, but does have substitutable biofuels that can displace petroleum-based diesel quantities. **Figure 46** displays U.S. EIA information on foreign imports into California for diesel, renewable diesel, and biodiesel. From 1986 to 2016, the largest annual import of diesel from a foreign source was roughly 9.4 million barrels of diesel in 2007. Since then, crude oil derived diesel has drastically fallen as a foreign-sourced import into California, only averaging 193,000 barrels per year from 2012 to 2016.

The decline of foreign imports between 2007 and 2011 aligns with a 14 percent drop in diesel consumption over the same period. After 2011, renewable diesel and biodiesel have become the prime sources of diesel imports from foreign sources as California's diesel demand has rebounded 12 percent over this period. From 2012 to 2016, renewable diesel became the largest source of foreign-imported diesel into California, averaging 2.8 million barrels per year (a high of 4.6 million barrels occurred in 2016). Biodiesel also outpaced crude oil derived diesel over that period, averaging 566,000 barrels per year with a high of 1 million barrels imported from foreign sources in 2015. It appears the resurgence in diesel fuel demand is being met by increased imports of foreign renewable-based diesel fuel substitutes.

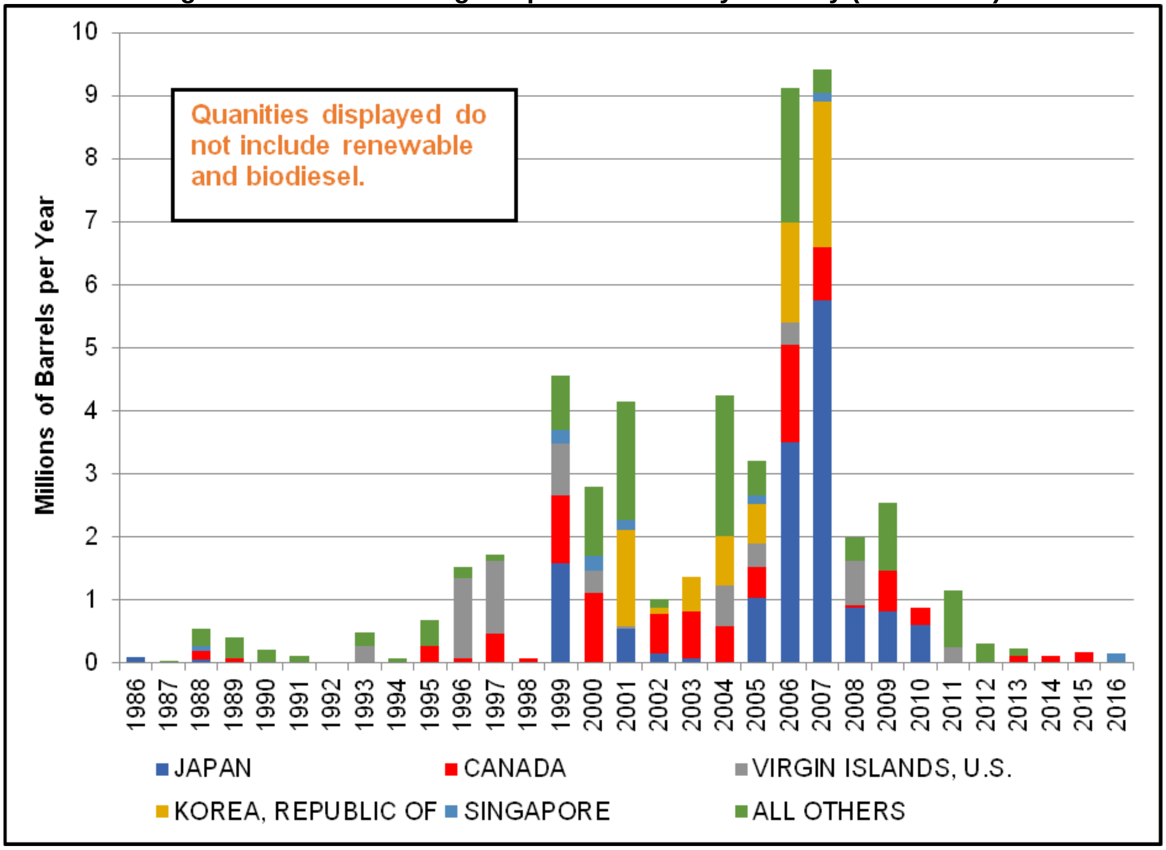
**Figure 46: Annual Foreign Imported Diesel, Biodiesel, and Renewable Diesel (1986–2016)**




Source: U.S. EIA

**Figure 47** shows the foreign country sources of crude oil-derived diesel product flowing into California from 1986 to 2016. Like gasoline, diesel has been imported from several locations (30 countries per U.S. EIA data). The largest source of foreign imported diesel was Japan at 15 million barrels of imported diesel total for the period. The second largest source came from Canada at 9.4 million barrels, 6 million barrels came from the U.S Virgin Islands, and another 5.8 million barrels came from South Korea.

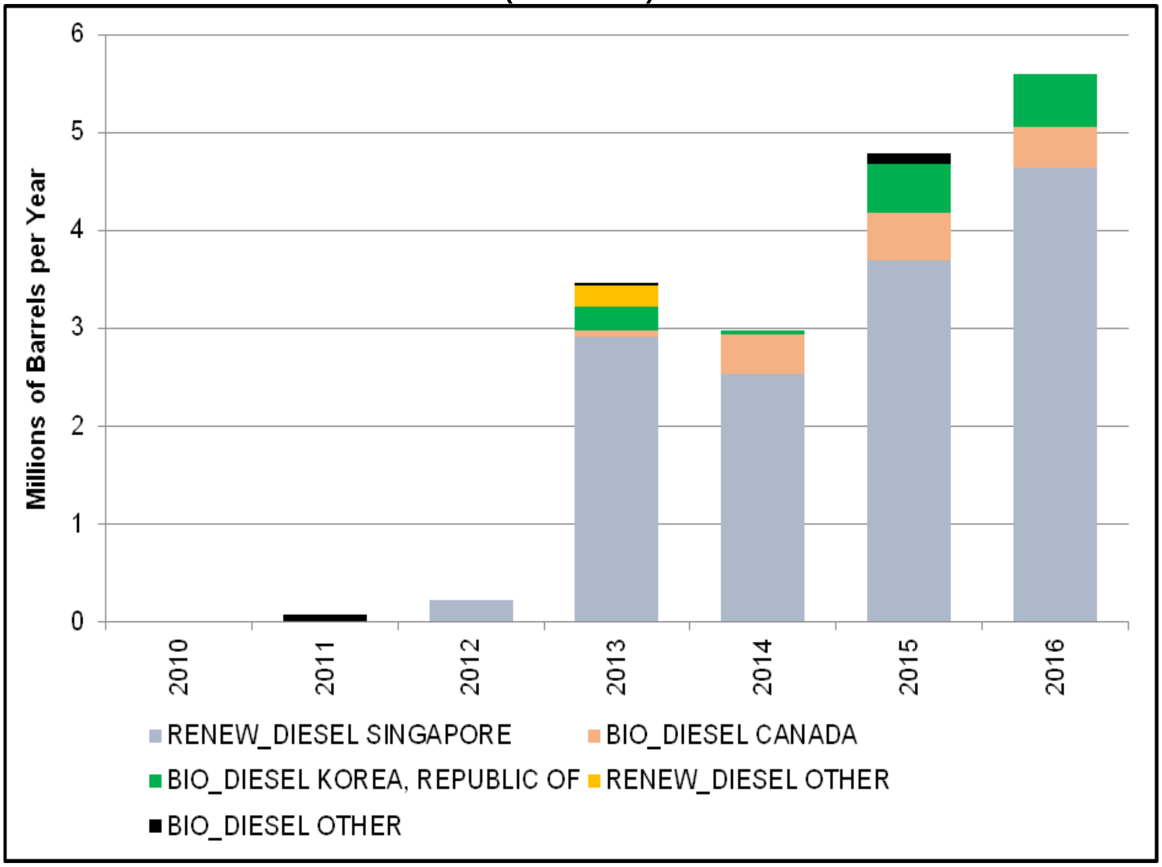
Figure 47: Annual Foreign-Imported Diesel by Country (1986–2016)




Source: U.S. EIA

**Figure 48** displays biodiesel and renewable diesel imports by country, starting in 2011 when the LCFS was readopted. The years 2011 and 2012 represented small totals as the LCFS compliance schedule was beginning the phase-in, with 75,000 barrels of biodiesel and 215,000 barrels of renewable diesel making its way to California in those years, respectively. Since 2013, renewable diesel import volumes have totaled at least 2.5 million barrels from Singapore. Neste's renewable diesel fuel refinery in Singapore is the closest foreign source. Biodiesel has come primarily from Canada and South Korea. More strikingly, renewable diesel imports have outpaced crude oil-derived diesel by a ratio of 27 to 1, and biodiesel has outpaced crude oil-derived diesel by a ratio of 4.7 to 1 since 2013.

**Figure 48: Annual Foreign Imported Biodiesel and Renewable Diesel by Country (2010–2016)**

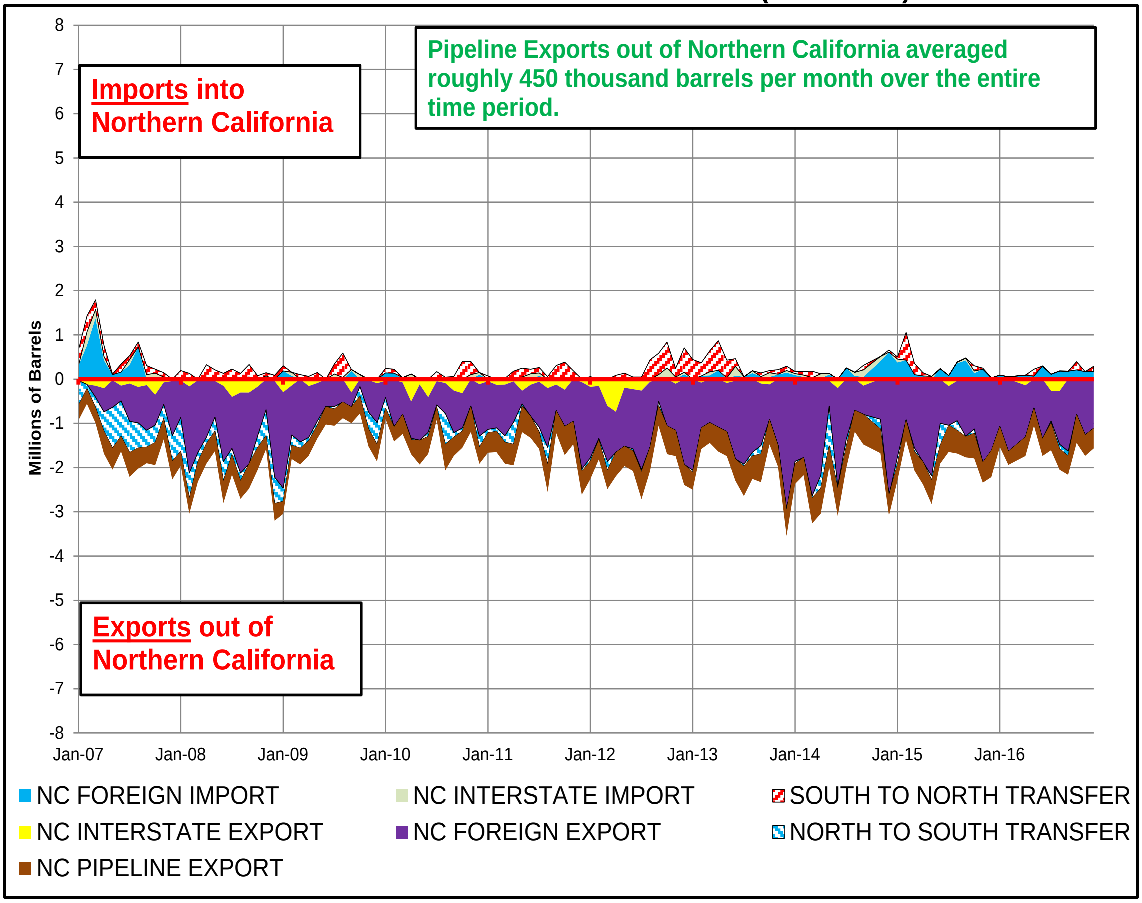



Source: U.S. EIA

As with gasoline, U.S. EIA information tells only part of the story. Using the same graphical structure that was used in the "Gasoline Flows" section, **Figure 49** shows monthly gross imports into and exports out of the Northern California region using Energy Commission-analyzed data. Northern California is an active diesel export hub, averaging 1.89 million barrels per month of diesel exports leaving the area. Most of that diesel is being shipped via marine vessel, which averages 1.16 million barrels or roughly 61 percent of exports. Another 25 percent (468,000 barrels per month) of exports are shipped by pipeline into northern Nevada to support diesel consumption in that market. The remaining 16 percent is either transferred to Southern California or shipped to another U.S. port. Product leaving by marine vessel went mostly to states and countries bordering the Pacific Ocean, with an occasional shipment crossing the Panama Canal into the Gulf of Mexico and the Atlantic Ocean.

Imports of diesel into Northern California are minuscule. Northern California gross imports averaged 278,000 barrels per month of diesel for the displayed period (roughly one-seventh the volume of exports). During the entire 2007-to-2016 period, 46 percent of all imports entering Northern California were south-to-north transfers, with another 46 percent of imports coming from foreign destinations.

**Figure 49: Monthly Gross Diesel Product Movements for Northern California—Includes Biodiesel and Renewable Diesel (2007–2016)**



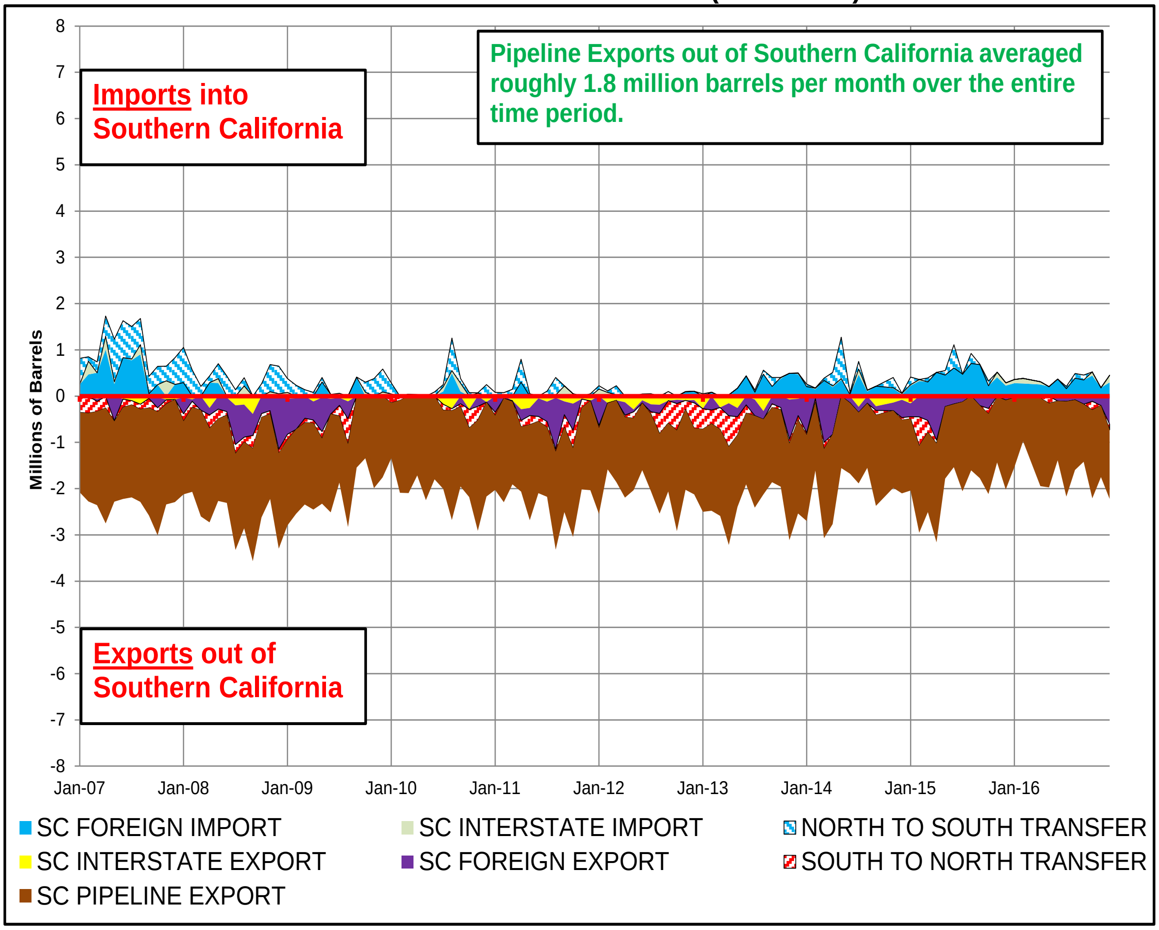

Source: Energy Commission

Like gasoline, Southern California supports diesel demand in the southern Nevada and western Arizona markets via pipeline exports (**Figure 50**). This movement of diesel averaged 1.8 million barrels of diesel per month and is roughly equivalent to Northern California's entire gross export average (1.9 million barrels per month). Of the 263 million barrels of diesel that left Southern California since January 2007, 81 percent or 213 million barrels of those exports have left the state by pipeline exports. Foreign destination exports are the second largest, averaging 228,000 barrels per month. South-to-north transfers were the third largest at 127,000 barrels per month and domestic (interstate) exports averaging 71,000 barrels per month. Exports have been trending downward since 2007. This downward trend has been mostly a result of declining pipeline exports, which averaged roughly 1.9 million barrels per month from 2007 to 2011, but only 1.7 million barrels per month since. This decline in pipeline exports can be attributed directly to the completion of the UNEV pipeline, which stretches from refineries in Utah to Las Vegas, Nevada, and started operations in 2012.

Imports into Southern California are small in comparison to exports, averaging 381,000 barrels per month during the displayed period. Like exports, imports appear to be trending downward, averaging 327,000 barrels per month from 2012 to 2016. Roughly 49 percent of those imports came from foreign sources, which averaged 185,000 barrels per month from 2007 to 2016.

Domestic imports into the area averaged 34,000 barrels a month; north-to-south transfers averaged 163,000 barrels per month.

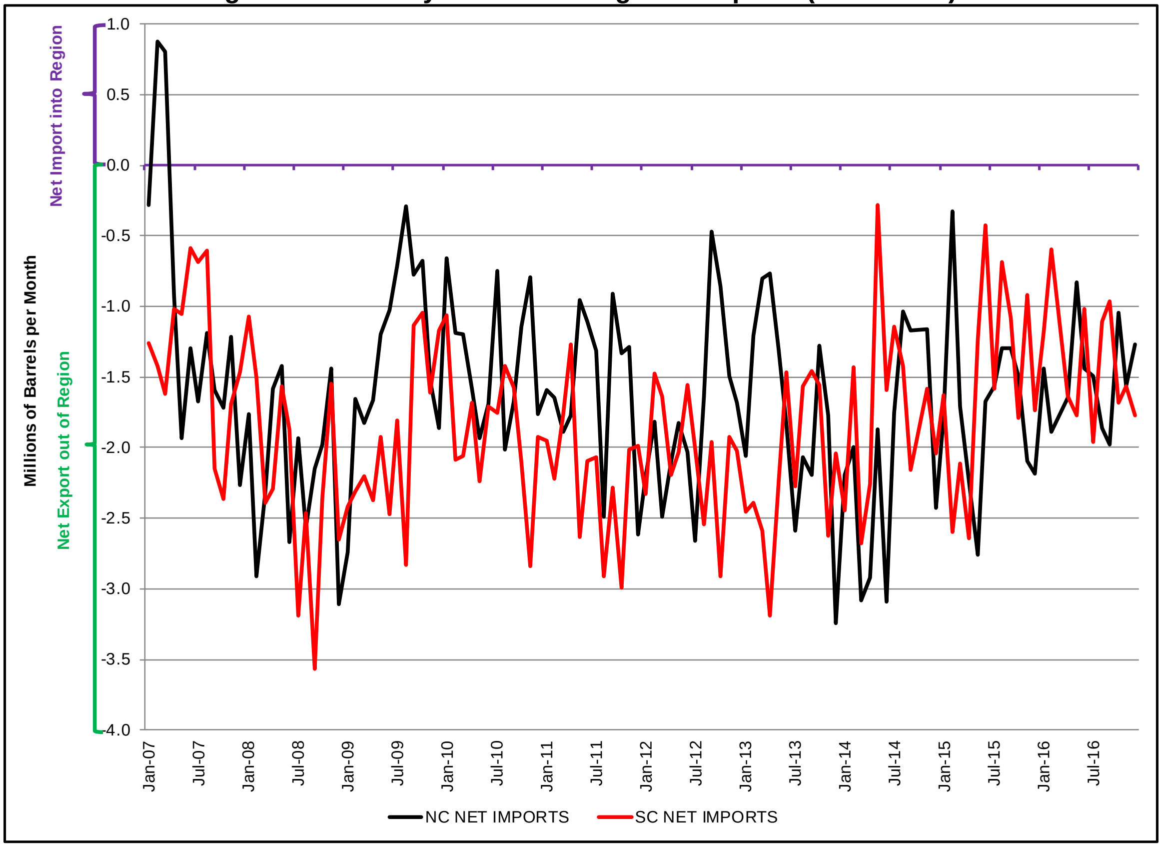
**Figure 50: Monthly Gross Diesel Product Movements for Southern California—Includes Biodiesel and Renewable Diesel (2007–2016)**




Source: Energy Commission

Both Northern and Southern California are net exporters of diesel. **Figure 51** displays the monthly net transfers leaving each area, which include pipeline and marine movements. Over the entire displayed period, each area appears to be going in opposite directions. Southern California averaged 1.9 million barrels a month in exports from 2007 to 2011 before falling to 1.78 million barrels a month from 2012 to 2016 period, due to falling pipeline exports. Northern California diesel net exports increased almost by the same amount that Southern California net exports decreased, going from 1.5 million barrels per month from 2007 to 2011 to 1.76 million barrels per from 2012 to 2016.

Figure 51: Monthly Net Diesel Regional Imports (2007–2016)




Source: Energy Commission

# Responses to Significant Refinery Disruptions

The California market is geographically isolated from other locations in the United States that produce gasoline. Pipelines connect California refining centers to distribution terminals in Nevada and Arizona, but these pipelines operate in only one direction–exporting gasoline and other transportation fuels to these neighboring states. No other petroleum product pipelines connect refinery centers in other states to California. This means that additional sources of gasoline supplied from outside the state are normally delivered to California in marine vessels, a journey that can take several days to arrange and complete from refineries in Washington State, and up to four weeks from refineries in other countries. In 2012 and 2015, this lack of fast resupply connectivity led to two price spikes of various lengths. Given the pronounced influence on price, this section of the chapter provides a detailed discussion of refinery disruptions.

Gasoline and gasoline-blending component imports into California are usually accomplished using marine vessels to minimize transportation costs and maximize the potential supply options outside the state for a refiner or trader. This means gasoline supplies can be imported from nearly any marine terminal in the world that has access to a refinery. That is why all the refiners in California (with the exception of facilities in the Bakersfield area) have their own marine terminal connected to the refinery or network of pipelines connected to a third-party marine terminal.

Although gasoline supplies could theoretically be imported into California using tanker trucks and rail cars, it would be highly unlikely and probably infeasible to do so when compared to marine vessel delivery. The only real benefit of using trucks to supply California from the outside, if necessary, is the reduced time to deliver additional gasoline supplies to the state—usually within a couple of days rather than a couple of weeks. But there are several potential drawbacks:

- Tanker truck transportation costs could be double or more than that of marine vessels.
- Tanker truck delivery volumes are very small (about 8,000 gallons or 200 barrels) and would equate to 150 truck deliveries per marine vessel.
- Spare trucking assets (both trucks and drivers) are normally scarce commodities that have necessitated using foreign drivers in the aftermath of hurricanes to distribute additional gasoline by tanker truck when pipelines not operating.
- The farther the supplies have to be trucked from outside California, the greater the number of additional trucks and/or drivers would be required due to the federal limit on consecutive hours of driver operations (10 hours)—not an issue for delivery by marine vessel.

Rail tanker cars are the primary means of importing ethanol into California, usually less costly than using marine vessels if these deliveries are accomplished by using unit trains of nearly 100 rail cars. However, the use of rail cars to import gasoline into California also has potential drawbacks:

- There are few, if any, distribution terminals in California that could receive and unload a rail car of gasoline—either no rail connection or proper equipment and plumbing connections.
- California refineries are not normally set up to receive and unload rail cars of gasoline; rather, they use their rail spur connections and equipment to handle liquefied petroleum gases (such as butane and propane), as well as sulfuric acid used in their alkylation units.
- Maximum rail tanker car capacity is about 34,000 gallons or roughly 810 barrels—equates to about 37 rail tanker cars per single marine vessel.

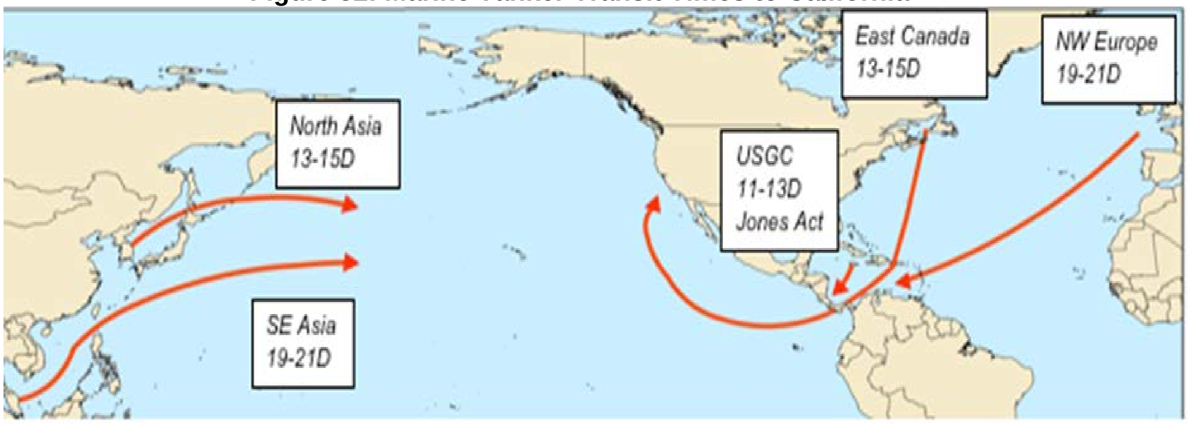
Assuming the use of tanker trucks and rail tanker cars is unrealistic for the reasons cited above, marine importation of gasoline in response to a price spike or refinery disruption requires, at a minimum, time to:

- Identify a supply source—1 day.
- Locate and arrange for a spot lease of a marine vessel—1 day.
- Allow transit time for the vessel to arrive at the supply source—1 to 3 days.
- Load the vessel with the non-California gasoline—1 day.
- Allow transit time to a California marine terminal—2 to 21 days.

  Total combined time is between 6 and 28 days.

All these steps combined require a minimum of several days for the nearest source and up to several weeks for the next nearest supply sources. **Figure 52** illustrates gasoline supply sources and approximate shipping times required to transport to a California marine terminal. Not shown is the transit route from Washington State refineries that could take a day or two.

**Figure 52: Marine Tanker Transit Times to California**




Source: Energy Information Administration (EIA)

### Price Spikes

California's gasoline market is nearly self-sufficient, so supplies of gasoline materials from outside California are not routinely needed to balance supply with demand. This means that when a significant unplanned refinery outage occurs in California, the isolated nature of California's gasoline market precludes rapid resupply from outside the state. A refiner that experiences an unplanned outage must acquire alternative sources of gasoline from other refiners and gasoline marketers in the state who are willing to sell a portion of their gasoline inventory at a higher price. During most of the year when the California gasoline market is in balance, there is excess gasoline (referred to as *unbranded gasoline*) available at a discount to independent service station owners. When a significant unplanned refinery outage occurs, however, large portions of this excess gasoline can be diverted (sold) to the refiner who had the unplanned outage to help fulfill contractual supply obligations to their customers. Independent retail station operators that do not have supply contracts then experience difficulty finding adequate supplies and/or have to pay the higher wholesale price during a price spike. Profiting from price discrepancy resulting when gasoline purchased in one market is immediately resold in another is referred to as an *arbitrage opportunity*.

Companies that import cargoes of gasoline to California are paid for the gasoline when the marine vessel discharges the load at a California marine terminal, not when the initial transaction is conducted. Many cargoes of imported gasoline are valued at the average price of gasoline on the spot pipeline market a day before and a day after the gasoline is discharged. There is a heightened risk that the initial arbitrage opportunity created by a price spike could dissipate by the time the marine vessel arrives in California, and the company would take a loss of the entire cargo that could be substantial. For example, a loss of 10 cents per gallon can equate to loss of $1.26 million on a shipment of 300,000 barrels of gasoline. This can come about due to the relatively brief nature of most price spikes in the spot gasoline market that usually peak within a couple to several days, and significantly decline by the time gasoline can be delivered to California. However, a significant unplanned refinery outage that lasts for many months creates a more chronic and extended supply shortfall that can keep California prices elevated for many months.

### California 2015 Gasoline Supply Disruption—Torrance and Tesoro Golden Eagle Refineries

The most recent example of a company gasoline production shortage leading to shifting of product based on arbitrage signals happened recently on February 18, 2015, at roughly 9:00 a.m. The Torrance refinery (then owned by ExxonMobil) experienced a large explosion that injured two workers. The U.S. Chemical Board later determined that a series of events led to an explosion of the refinery electrostatic precipitator, causing the refinery to be fully shut down. The Torrance refinery produces 10 percent of California's total gasoline supply with a nameplate capacity of roughly 150,000 BPD of crude oil processing and is the sixth largest refinery in California by nameplate capacity. The damage to the electrostatic precipitator (ESP) structure took the primary gasoline-producing process equipment, the fluidized catalytic cracking unit, and the alkylation unit, offline for about 17 months.

In the subsequent two weeks, the deferential between the California and U.S. average reformulated regular gasoline price rose from roughly $0.44 during the week of February 9, to $0.63 during the week of February 23. California retail gasoline prices then spiked three times in March, May, and July 2015. Southern California was hardest hit by these price increases, with the average Los Angeles regular gasoline price reaching a high of $3.53 in March, $3.99 in May, and $4.31 in July. In San Francisco, the first two spikes were similar with a high of $3.44 in March and $3.73 in May, but in July a high of $3.56 was down from May.

The second 2015 supply disruption involved Tesoro's Golden Eagle Refinery, which took place before the Torrance incident. The Martinez refinery was undergoing maintenance at the beginning of January 2015, and then faced a labor strike at the beginning of February. Due to the labor dispute, and reduced operations and capacity immediately before the dispute, Tesoro accepted the striking workforce's offer to safely shut down operations at the Golden Eagle until the dispute was resolved. The refinery did not return to full operations until the end of April, as it was necessary to safely restart refinery equipment after being idle during February and March. Tesoro's Golden Eagle Refinery has a nameplate capacity of 166,000 BPD of crude oil processing and is the fourth largest refinery in California by nameplate capacity.

The Energy Commission's Petroleum Market Advisory Committee[42] convened several public meetings that covered this incident and subsequent price spike in detail. In particular, a presentation docketed to these proceedings walks through the primary factors that contributed to such a strong price response and the actions taken by various market participants to bring

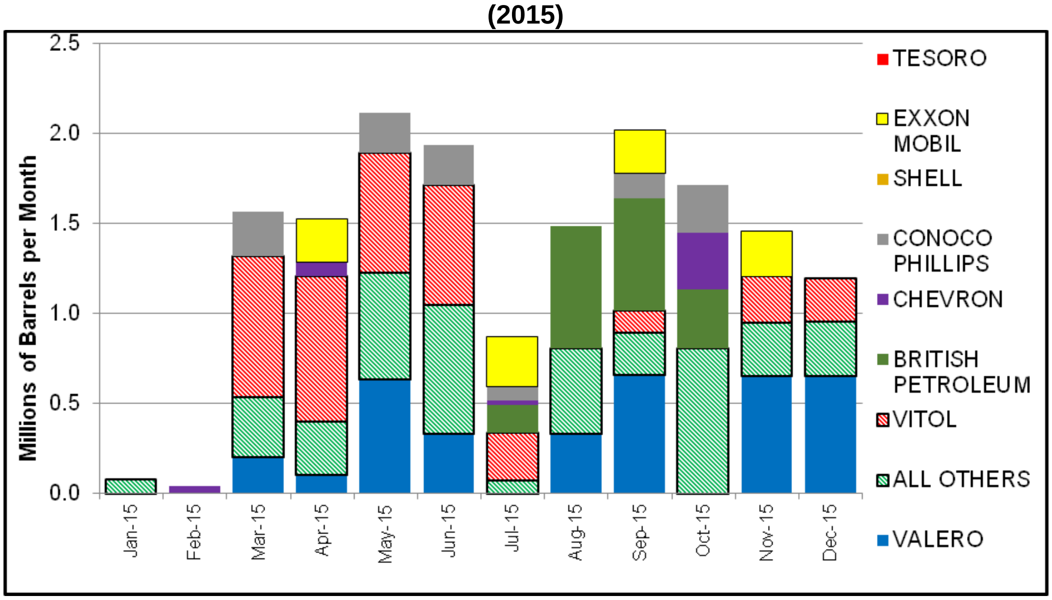
---

42 In December 2014, the California Energy Commission assembled the Petroleum Market Advisory Committee to help assess petroleum market issues of interest to the Commission. After the February Torrance refinery explosion, the committee was instructed to look at cause for the prolonged gasoline price spikes and discuss policy options for addressing them. Information on Petroleum Market Advisory Committee can be found at http://www.energy.ca.gov/assessments/petroleum_market/.

additional supplies into the market to compensate for the diminished gasoline production capability of the Torrance refinery.

**Figure 53** displays the monthly response to these two refinery issues in foreign-sourced gasoline and gasoline blendstock imports, using U.S. EIA company-level import data. Foreign imports into California were small in January 2015, at 80,000 barrels. By May, foreign gasoline imports increased to a high of 2.1 million barrels. What is also readily seen in **Figure 53** is that California refinery companies were typically not the importer of record for gasoline during this period. Starting in March, the only months in 2015 that didn't see either Vitol, British Petroleum, and all other nondisplayed importers import at least 50 percent of the gasoline into California were September, November, and December. During each of those months, it appears that Valero provided the make-up in shortfall, becoming the largest importer of record. ExxonMobil, which still owned the Torrance refinery in 2015, only showed as an importer of gasoline in April, July, September, and November. This leads to the assumption that spot market gasoline was purchased from another refinery or gasoline importer to cover contractually obligated gasoline volumes normally produced by the Torrance refinery. It was also apparent that foreign gasoline product imports did not flood the market as soon as the Torrance refinery accident occurred due to the time lag to obtain imports from foreign sources that was discussed earlier.

**Figure 53: Monthly Foreign-Imported Gasoline and Gasoline Blendstocks by Company (2015)**




Source: U.S. EIA

The Torrance refinery accident left the market with a sudden shock to its gasoline supply. The nearest refinery complex, outside Northern California, is the Puget Sound area in Washington State and refineries in British Colombia. Neither transfer is quick by marine vessel. Adding a second complication, gasoline cargoes originating from another U.S. marine terminal must be shipped in a marine vessel meeting Jones Act Standards—constructed in a U.S. shipyard, owned and insured by a U.S. company, and manned by a crew with U.S. citizenship. Shipping costs in these vessels are typically two to three times greater than a foreign-flagged marine product tanker. Besides the greater vessel cost, Jones Act product tanker availability for spot charters can be scarce as most of these of marine vessels are already in service.

Before 2012, interstate and foreign imports into Southern California were common. Easier north-to-south gasoline movements within California, however, displaced these imports after January 2012. With the loss of Golden Eagle at the beginning of the year combined with the sudden loss of the Torrance refinery, Southern California experienced a shortfall in production combined with Northern California being tight on supply and unable to quickly move product to address the loss in gasoline supply. Bring gasoline product from the Puget Sound proved difficult, as Shell's Puget Sound Refinery had already begun planned maintenance, with other refineries in the area scheduled for the following months.

U.S. EIA would later summarize the PADD 5 refinery maintenance period in its February 2015 report[43] on U.S. refinery maintenance as:

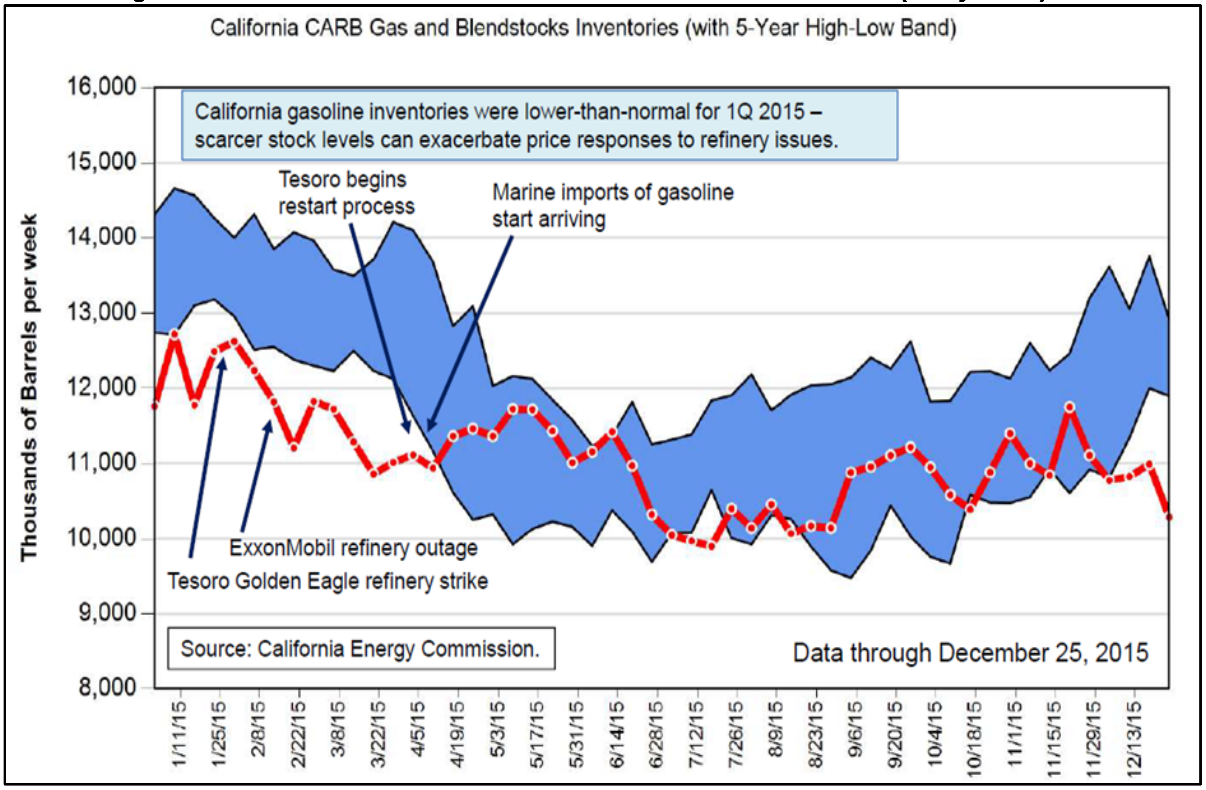
> *With almost all planned Fluid catalytic cracking unit maintenance in the West Coast region, which includes Arizona, California, Oregon, Washington, Nevada, Alaska, and Hawaii, already complete, and with relatively light CDU maintenance in a region that produces more distillate than it consumes, supplies of gasoline and distillate fuel are expected to be adequate to meet demand in PADD 5 during the first half of 2015, barring disruptions to supply resulting from the recent unplanned refinery outage in Southern California . On February 18, the ExxonMobil refinery in Torrance, California experienced an explosion that could have a significant impact on in-region production of gasoline and distillate; however, it is too soon to assess what that impact might be. U.S. EIA will continue to monitor the situation. As of February 20, gasoline inventories are at the low end of the 5-year range, and are sufficient to supply 21 days of average demand, 1 day below average. Distillate inventories remain above average and are sufficient to supply 29 days of average demand.*
>
> *Because the West Coast is relatively isolated from other U.S. markets and located far from international sources of supply, the region is very dependent on in-region production to meet demand. Planned FCCU maintenance, which was concentrated in January, is expected to complete in February, and there is no maintenance planned from March through June. Inventories of gasoline at the start of February were sufficient to supply 22 days of average demand, a level consistent with average historical levels.*

Energy Commission *Weekly Fuel Watch* reports for that period confirms U.S. EIA's observations that gasoline inventories in California were low at the beginning of 2015 (**Figure 54**).

---

[43] EIA Refinery Outages: First Half 2015: https://www.eia.gov/petroleum/refinery/outage/archive/pdf/outage_feb2015.pdf

**Figure 54: California Gasoline Inventories Lower Than Normal (Early 2015)**

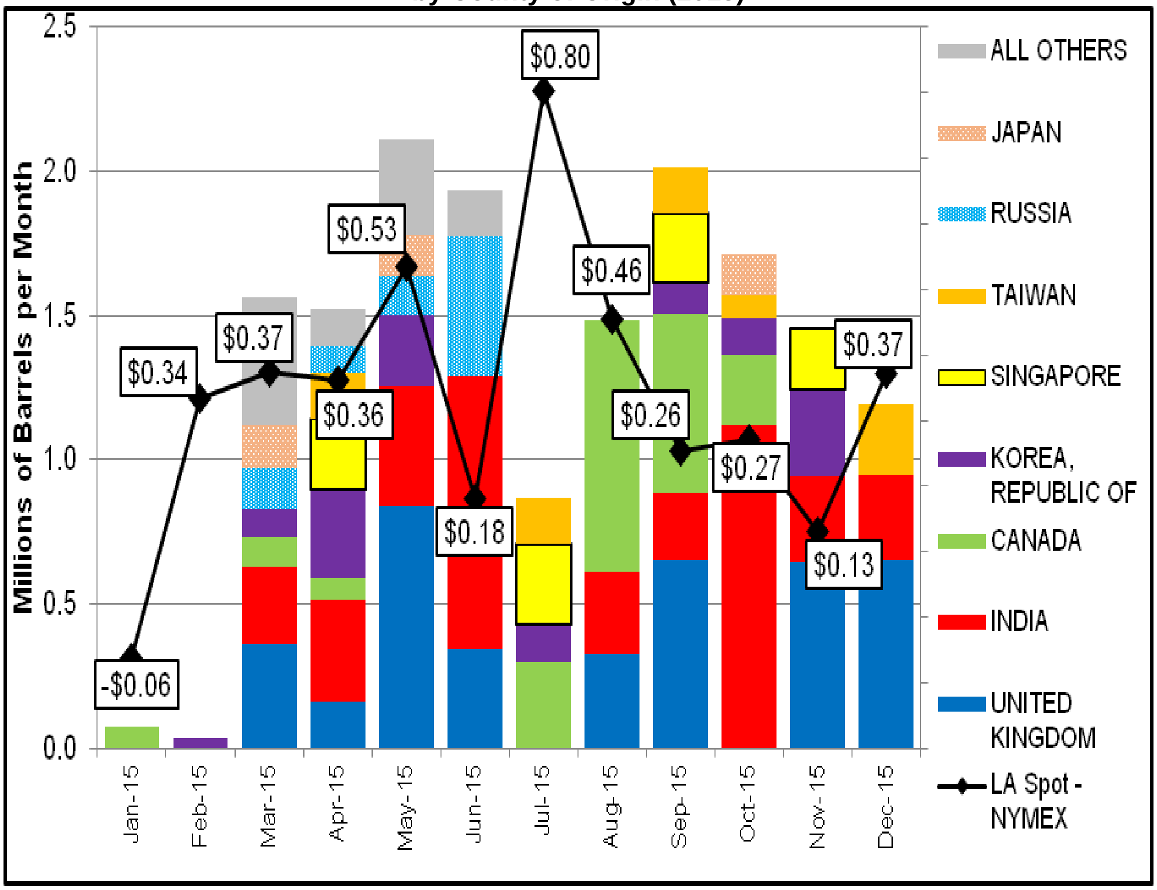



Source: California Energy Commission

With the entire PADD 5 area experiencing tight market conditions in the first quarter of 2015, conditions planned for but with little capacity to address when faced with an unforeseen event, the Torrance refinery accident compelled going out of the region to secure gasoline product. To show the import-export response to these events, staff performed the same gasoline movement analysis as in the “Gasoline Flows” section but focused on the 2014 to 2016 period. This analysis provides more detail on the size of the shortage in the Southern California hub, since *Weekly Fuel Watch* reports on production of fuels include imported gasoline and gasoline blendstocks (production is measured by the volume that leaves a refinery gate), granting a more accurate reflection on how this unplanned event was handled.

**Figure 55** displays the same gasoline import volumes as **Figure 53,** but broken out by country of origin. In March 2018, when imports began to rise, the United Kingdom became the primary source of gasoline imports. California was able to draw from eastern Canada as well, but other imports came from India, South Korea, Russia, and Japan, all countries requiring roughly a month for delivery. Overall in 2015, India proved to be California’s primary source of foreign gasoline imports into California at 4.2 million barrels of gasoline product (or 176.4 million gallons). United Kingdom was the second largest source at 4.0 million barrels. Canada was the third largest source at 2.3 million barrels of gasoline product, with 1.7 million barrels of imports occurring in August, September, and October.

**Figure 55: Monthly Foreign Imported Gasoline and Gasoline Blendstocks by County of Origin (2015)**



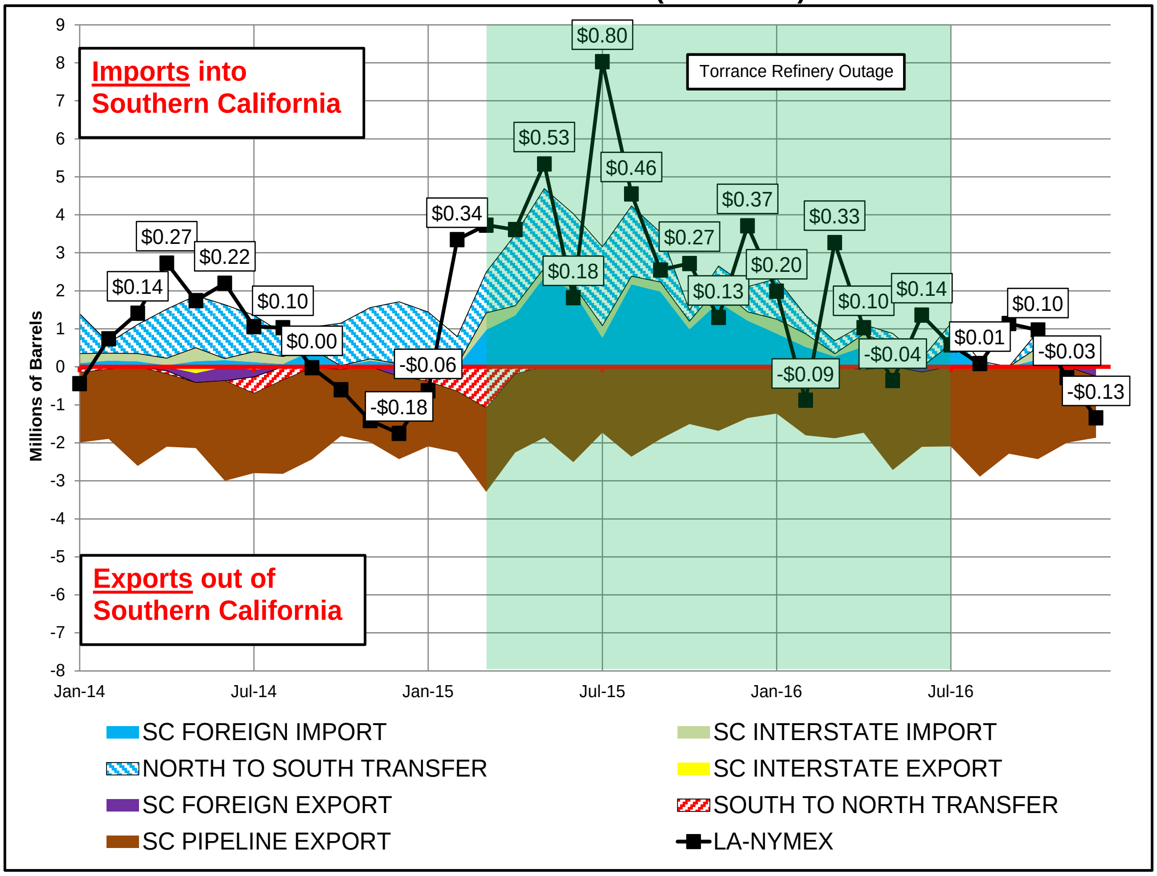

Source: U.S. EIA

Also included in **Figure 55** is the Los Angeles spot market price for gasoline to New York Mercantile Exchange (NYMEX) spot gasoline price monthly average differentials (LA-to-NYMEX) for 2015. Likely due to the long shipping times for moving petroleum product, it appears that foreign imports into California have roughly a one-month delay in responding to a price signal. For example, when the LA-to-NYMEX differential increased to $0.34 in February, partially due to the Torrance refinery accident, it was not until March that foreign imports began showing up in noticeable amounts. The March differential increasing to $0.37 kept gasoline imports into California at roughly the same level in April. The slight fall in the differential to $0.36 in April, still high in comparison to the historical average of $0.16, pushed May foreign gasoline imports up even further to 2.1 million barrels of foreign imports in that month (2015 high). This correlation appears to break down in some locations as the increase in the differential in May to $0.53 was followed by a decline of imports for June, but June's average differential of $0.18 likely diverted shipments away from California in that month and led to July's low import totals. With the spike in the differential occurring in July, averaging $0.80 for that month, and the differential averaging in the $0.30 range for the rest of the year, foreign imports remained above 1 million barrels per month for the rest of 2015.

**Figure 56** uses the same Energy Commission analysis of gasoline product movements as **Figure 44** but focuses in on the 2014 to 2016 period. Also included in **Figure 56** is a green box denoting the full duration of the Torrance refinery primary gasoline-producing equipment (the fluidized catalytic cracking unit and alkylation units) nonoperation, along with monthly LA-to-NYMEX differentials (black line and value boxes). In 2014, gasoline product imports into the area totaled roughly 1 million barrels per month, with Northern California providing most of that inflow of product. Higher differential prices in the second quarter of 2014 appeared to attract some foreign and domestic imports into the Southern California region. In the third and fourth quarters of 2014, the differential drops noticeably, and domestic imports disappear entirely with small amounts of Canadian gasoline product entering the area. Pipeline exports leaving the area averaged roughly 2 million barrels per month, fluctuating from 1.75 million to 2.6 million barrels per month. From roughly December 2014 to April 2015, there is an atypical north-to-south transfer of gasoline product 2.3 million barrels over those five months. Close inspection of those transfers, using public State Lands Commission data, reveal that these were mainly Tesoro shipments likely to cover the decreased output from the Golden Eagle Refinery, which was down until the end of April.

Before the February 18, 2015, Torrance Refinery ESP explosion, both the LA and San Francisco (SF) spot markets were signaling tightness, with the daily LA-to-NYMEX spot differential increasing to $0.19 (a $0.10 increase from the previous day) and the SF-to-NYMEX spot differential increasing to $0.10 (an increase of $0.03 from the previous day) on January 30, 2015. Both differentials would increase further prior to the February 18 event, with the LA-to-NYMEX rising further in early February, finishing on February 17 at $0.33 (almost double the historic average of $0.16). This increase in the LA-to-NYMEX differential would be a signal to the international markets that Southern California was tight on product even before the Torrance refinery accident. Additional evidence of tightening in the California gasoline market comes from the BOE gasoline taxation reports that show California gasoline sales increasing from 39 million gallons a day in January 2015 to 41 million gallons a day in February 2015, caused by falling retail regular gasoline prices in California going from $2.87 in December 2014 to $2.70 in February 2015.

**Figure 56: Monthly Gross Gasoline and Gasoline Blendstocks Product Movements for Southern California (2014–2016)**




Source: Energy Commission

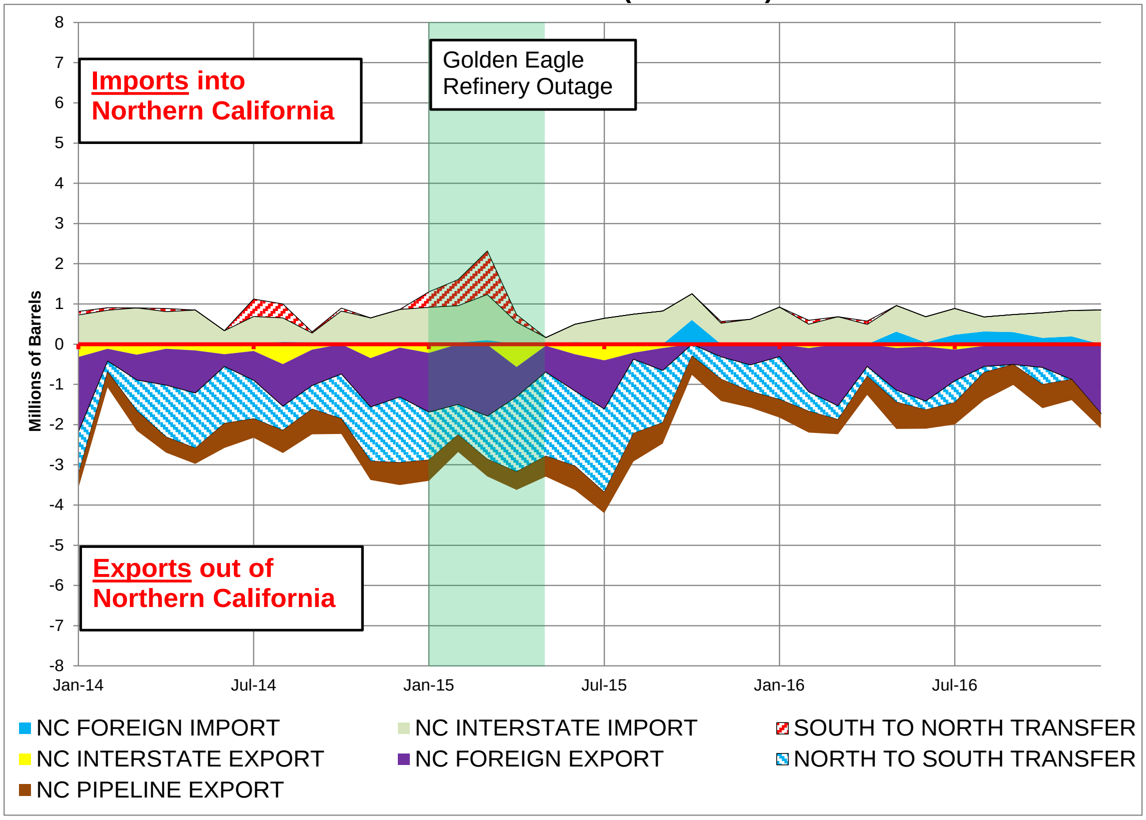
In the days after the Torrance refinery explosion, both LA-to-NYMEX and SF-to-NYMEX spot differentials increased further as the California market got even tighter, reaching a February high of $0.85 and $0.71, respectively. While both differentials would later fall from those highs, the April 2015 LA-to-NYMEX differential would average $0.36 as the market attempted to attract foreign imports into the area as both Northern California and the rest of the West Coast remained without much spare gasoline production capacity to help with the loss in product in Southern California. Yet despite rapidly rising Californian retail regular gasoline prices reaching $3.75 in May, BOE gasoline sale figures show that Californians did not slow down their gasoline consumption, maintaining the same 41-million-gallons-a-day consumption levels as February in March, April, and May, providing no demand-side relief to the market. Tesoro's Golden Eagle Refinery made a full return for May, which cut the need for south-to-north transfers to zero and increased the flow of gasoline from north to south from 1.87 million barrels in April to 2.09 million barrels in May. Even with this additional production fully back on-line, the LA-to-NYMEX differential increased to $0.53 in May, signaling a further tightening market, as gasoline inventory levels in both Northern and Southern California were consistently below five-year lows for the first quarter of 2015.

By the end of May, the California inventory situation improved. Inventory levels in both Southern California and Northern California had once again returned to the respective five-year high-low bands, and production in Northern California went into overdrive, producing consistently above its previous high-low norms (**Figure 54**). Southern California production remained depressed, but news of ExxonMobil attempting to seek a waiver to tie back into the older, decommissioned ESP structure entered the market giving signs of potential relief. While returning the ESP unit to working status would allow the Torrance refinery to restart its main gasoline-production equipment again, this older air pollution reduction structure no longer met local air quality standards. Nevertheless, these strands of good news appear to have helped lower the LA-to-NYMEX to an average of $0.18 in June.

This good news was short-lived and had significant consequences to imports and exports in Southern California. With the fall in the LA-to-NYMEX differential in June, both foreign imports and north-to-south transfers began to fall. Pipeline movements from Southern California to Arizona and Nevada, which had been tapering off in the wake of the accident, increased from 1.8 million barrels per month to 2.5 million barrels per month on signs that the supply situation would be returning to normal. On the demand side, June proved to be a popular driving month, with California gasoline sales increasing to 42 million gallons a day, despite the $3.52 average California regular gasoline price. But this increased demand by the market proved to be unsustainable. At the beginning of July, Southern California inventories dropped suddenly from the middle of the five-year high-low band to below previous low values. Southern California production was unable to increase as the ExxonMobil proposal was unable to gain local air quality management district approval, and suddenly Southern California was short on gasoline product again. On top of that, the low LA-to-NYMEX differential in June appears to have pushed additional foreign imports away, making July the lowest foreign import month during the year. With this shortage, the LA-to-NYMEX differential in July spiked dramatically to $0.80 to get product to flow into the region.

While important in the lead-up to the 2015 California supply situation, the Northern California import-export situation was not as dire as the Southern California situation (**Figure 57**). During the Golden Eagle Refinery outage, north-to-south transfers fell to a low of 757,000 BPD in February, and south-to-north transfers reached a high of 1.08 million barrels in March. Pipeline movements to Nevada did shrink in the beginning of 2015, averaging 436 million barrels per month for February, March, and April. With the Torrance refinery accident, north-to-south transfers of gasoline product went from the February low to averaging 1.9 million barrels per month from April to August 2015. Usual foreign export of off-specification gasoline products shrank to 155,000 barrels in August 2015 after averaging 800,000 barrels per month for the 2012-to-2016 period.

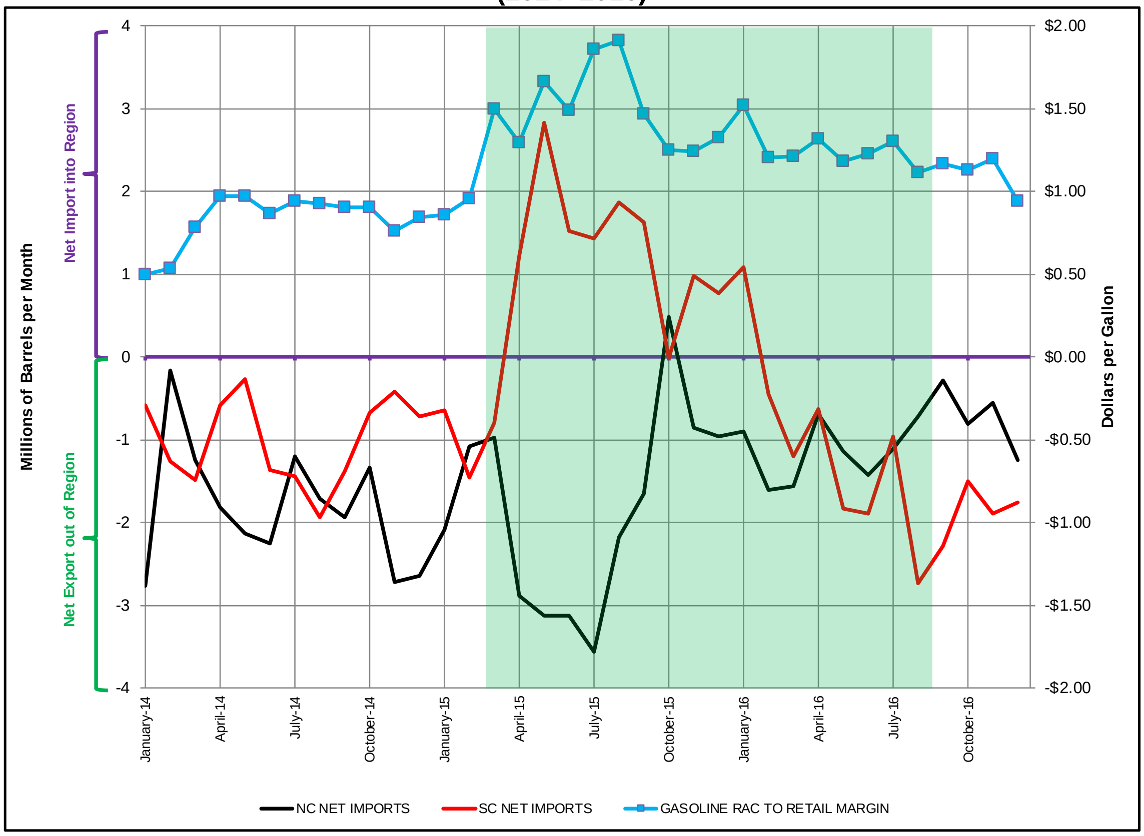
**Figure 57: Monthly Gross Gasoline and Gasoline Blendstocks Product Movements for Northern California (2014–2016)**




Source: Energy Commission

With all the difficulties at the beginning of 2015 for California and PADD 5 refineries, the Southern California market appeared to have had the most difficult time responding. **Figure 58** displays the net import-export balance for each area, with the green box denoting the Torrance refinery outage. As seen in **Figure 58** and in **Figure 45**, Southern California had been trending as a net exporter of product before 2015. The reduction of gasoline production from processing crude oil at the Torrance refinery changed that trend, making Southern California a net importer, averaging 1.7 million barrels of imports into the region between April and September. This had a noticeable influence on California's average crude oil price (RAC or *refiner acquisition cost*) to pretax retail gasoline price, sending it to a high of $1.91 versus the 2014 average of $0.75. While detailed analyses of these costs are beyond the Energy Commission's data collection, it can be assumed that some of those costs come from the need to import gasoline product from locations such as India and the United Kingdom. Northern California did attempt to address this situation with high production level in that region sustained for six months.

**Figure 58: Monthly Net Gasoline and Gasoline Blendstocks Regional Imports (2014–2016)**




Source: Energy Commission

Based on this flow analysis, it appears that the 2015 gasoline shortage created a roughly 3 million barrels per month (126 million gallons) shift in the net-importer balance in Southern California (average net exporter of 1 million barrels in 2014 and 1.8 million importer from April 2015 to June 2015). This 126 million gallon shift also represents roughly 10 percent of California's average monthly consumption in 2015, the same amount of gasoline that the Torrance refinery is estimated to produce from its gasoline-producing equipment.

## Retail Distribution

Retail fueling stations in the United States have evolved from facilities that, in the early years of automobile development, sold fuel and lubricants, and provided repairs to motorists. A number of stations in more remote portions of the nation's roadways also provided lodging. However, the days of helpful attendants (**Figure 59**) and garage repair services are all but a memory.

**Figure 59: Servi-car Service at Union Oil Gas Station – 4004 Wilshire Blvd. (1932)**

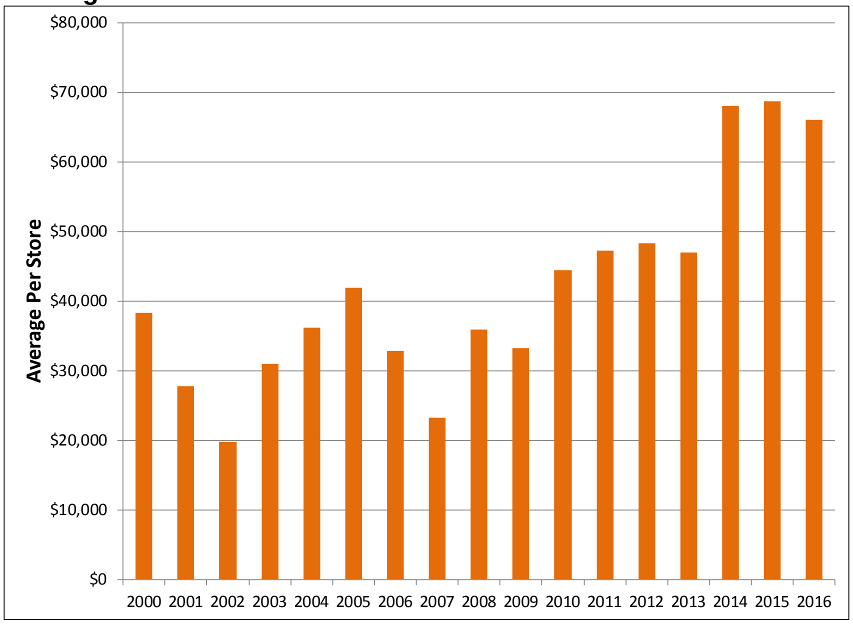

Source: Theoldmotor.com

Gasoline stations have been transformed into fueling locations that offer a plethora of nonfuel goods and services designed to enhance revenue streams and increase profitability. The early roots of the convenience store can be traced back to the late 1920s when the Southland Ice Company of Dallas, Texas, started selling everyday fresh goods such as eggs, milk, and bread from its ice docks. That company now referred to as 7-Eleven, has transformed into a business with more than 18,000 convenience stores in 18 countries.

## United States

During 2016, more than 80 percent of the gasoline sold to the public nationwide was through convenience stores. These businesses have continued to be profitable over the last 17 years, averaging nearly $42,000 per store in pretax profits between 2000 and 2016. Recently, pretax profits jumped 42.3 percent from the 2011-2013 average of $47,480 per store to the 2014-2016 average of $67,605 per store. **Figure 60** shows that these profits are not steady and can fluctuate.

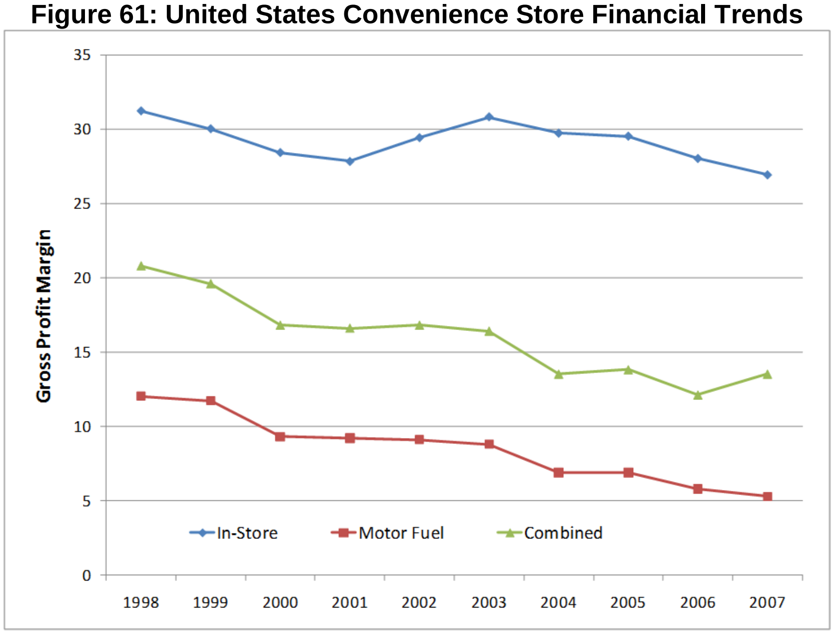
**Figure 60: United States Convenience Store Pretax Profits**




Source: NACS State of the Industry Reports data

Profit margins for convenience stores across the United States show that in-store sales (nonfuel) have a consistently higher and steadier profit margin, relative to that of the steadily declining profit margins for fuel sales as depicted in **Figure 61**. Declining gross profit margins for convenience store motor fuel sales can be interpreted to indicate that retail store operators are pricing retail gasoline and diesel fuel at increasingly competitive prices and lower profit margins (as a percentage of total price) to attract a sufficient number of customers purchasing nonfuel commodities to help sustain overall profitability.

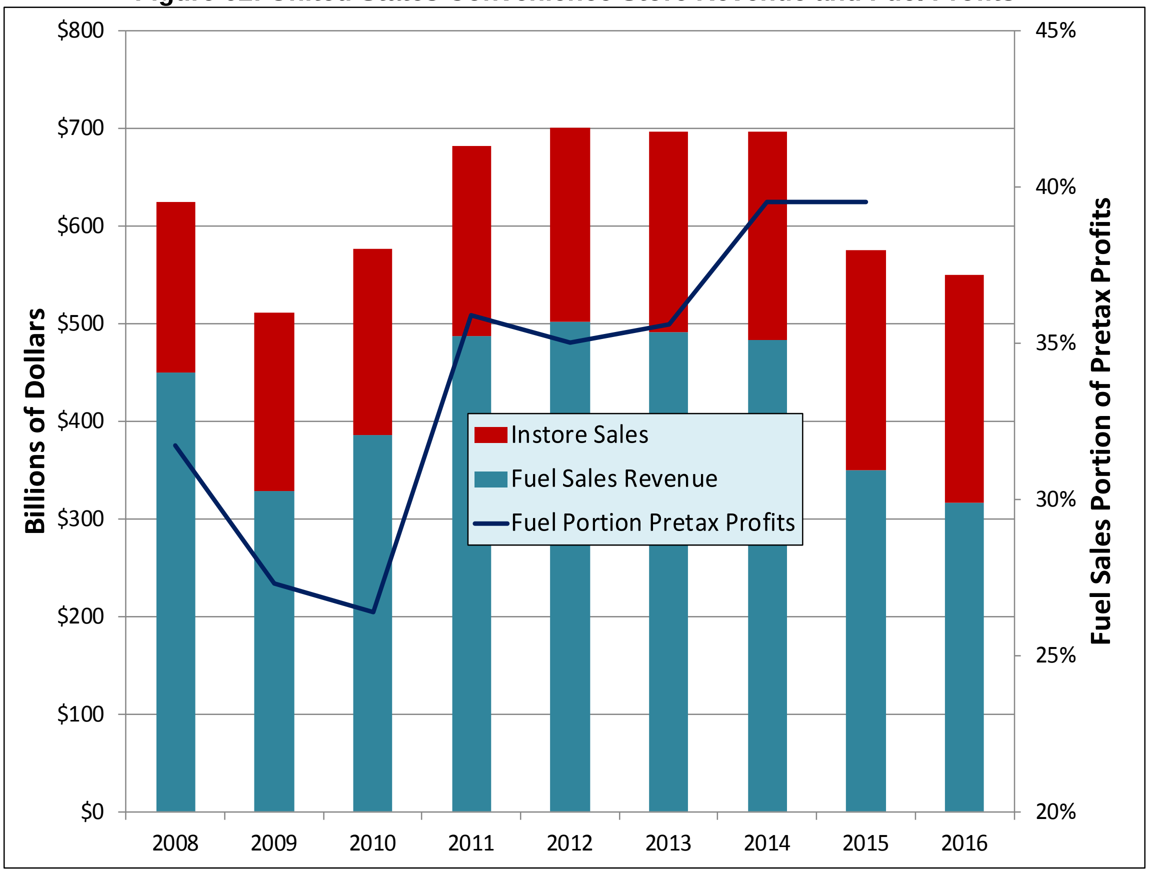
**Figure 61: United States Convenience Store Financial Trends**




Source: NACS State of the Industry Reports data

Fuel sales represent the majority of revenue for convenience stores but are less than 40 percent of pretax profits. The contribution of pretax profits from fuel sales has been growing since 2010, as depicted in **Figure 62**. The recent trend of increasing fuel profitability may reflect the declining number of retail stations throughout the nation.

**Figure 62: United States Convenience Store Revenue and Fuel Profits**

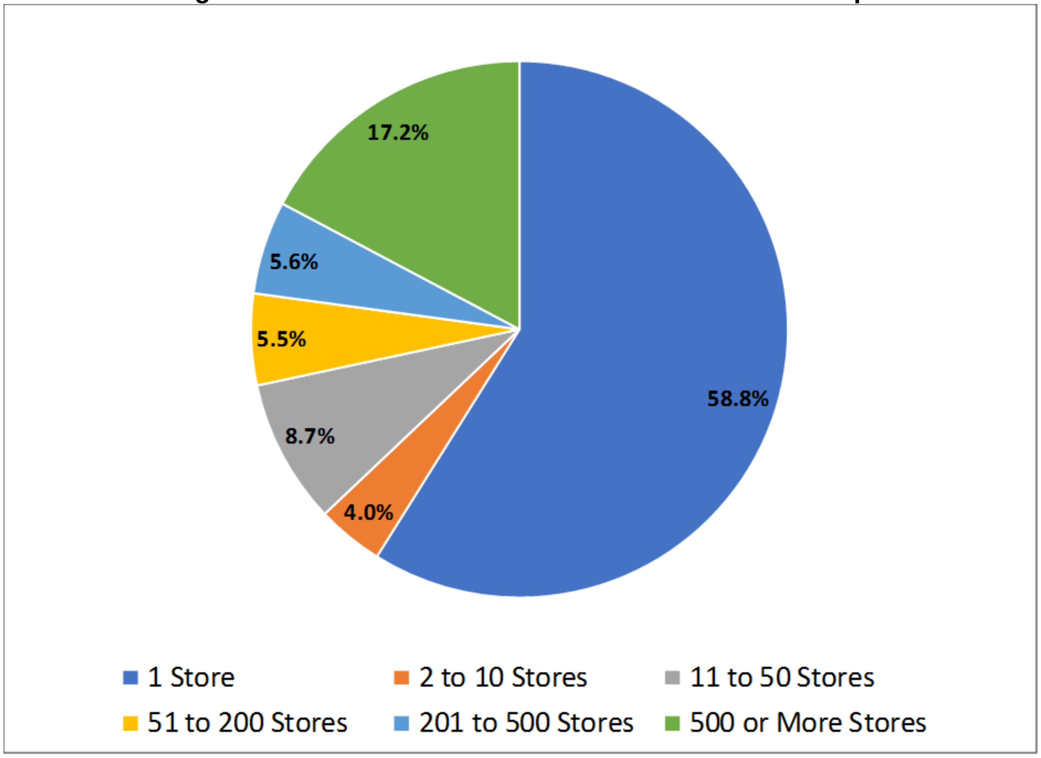



Source: NACS State of the Industry Reports data

Ownership of retail stations in the United States continues to evolve as major oil companies reduce the number of stations that they both own and operate. As of June 2016, the top five vertically integrated oil companies (Chevron, Shell, ExxonMobil, BP, and ConocoPhillips) still owned and operated 0.25 percent of the convenience stores selling transportation fuel. The majority (58 percent) of convenience stores are single-owner facilities, meaning that location is their sole convenience store business. **Figure 63** shows the remaining breakdown of ownership.

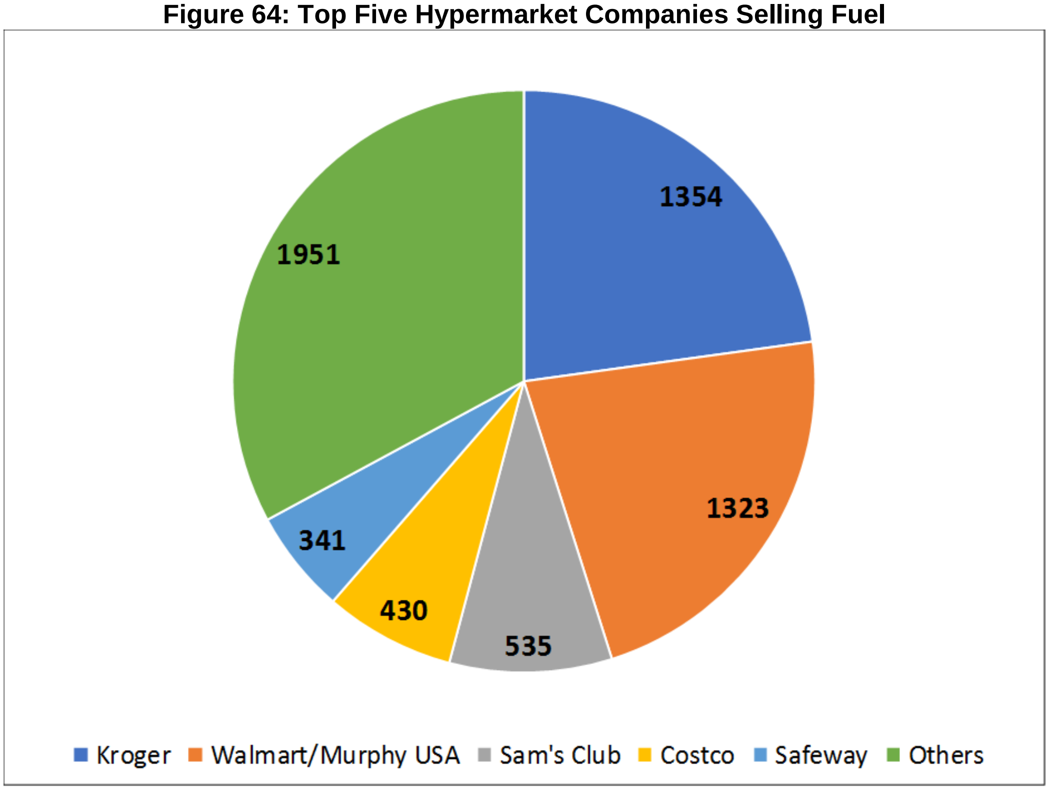
Another trend is availability of fuels at big box stores or hypermarketers such as Costco. These locations typically offer a greater number of fueling dispensers and space such that their fuel sales are higher than a typical convenience store selling fuel. Nationwide, these stores sold roughly twice the volume of fuel than a typical retail outlet. According to Energy Analysts International, there were 5,934 of these hypermarketers selling fuel as of May 2016. **Figure 64** shows a breakdown of the top five companies.

**Figure 63: United States Convenience Store Ownership**




Source: NACS/Nielsen 2017 Convenience Industry Store Count

**Figure 64: Top Five Hypermarket Companies Selling Fuel**




Source: NACS/Energy Analysts International

## California

The Energy Commission conducts an annual review of locations selling transportation fuel to the public, referred to as the A15 Survey. **Table 7** shows the number of report responses, estimated total number of fuel outlets, and types of fuels available from 2009 to 2015.

**Table 7: Summary of California Annual Retail Fuel Report (2009–2015)**

| Reporting Year | Gasoline | Diesel | E85[1] | Propane | Natural Gas[3] | Total Stations Survey Responses | Total Stations Estimated |
|---|---|---|---|---|---|---|---|
| 2009 | 8,138 | 3,826 | 30 | 726 | 52 | 8,369 | 9790 |
| 2010 | 7,707 | 3,715 | 36 | 679 | 42 | 7,965 | 9800 |
| 2011 | 8,036 | 3,942 | 42 | 809 | 48 | 8,343 | 9710 |
| 2012 | 7,748 | 3,847 | 51 | 805 | 32 | 8,038 | 10000 |
| 2014 | 6,369 | 3,416 | 56 | 714 | 29 | 6,594 | 10040 |
| 2015 | 7,240 | 4,095 | 81 | 573 | 139 | 7,516 | 9,718 |

Source: California Energy Commission

Stations by fuel type will not equal total respondents due to stations often dispensing multiple fuel types.

Source: Energy Commission

Because not all stations are accounted for through the survey, staff uses a statistical method to estimate the total number of outlets that may have been operating in a particular year. **Table 8** lists all of California's counties and the number of sites that completed surveys versus the total number of sites estimated to be selling transportation fuels to the public.

**Figure 65** depicts gasoline sales collected from the report, as well as a projection for total estimated sales in each county. Urban counties have the greatest quantity of fuel sales due to larger populations and higher station counts. Los Angeles is the top county with total estimated gasoline sales of 3.465 billion gallons or 22.9 percent of state totals. The top Northern California county, Santa Clara, was at 727 million gallons or 4.8 percent of state totals. **Figure 66** ranks the counties by average gasoline sales per report respondent per month. The 2015 average gasoline sales by each responding site was 133,500 gallons per month. Orange County had the highest average monthly throughput of 184,200 gallons per month. All of the counties above the statewide average are urban, whereas the lowest average monthly throughput locations are in rural counties.

## Table 8: Summary of California Annual Retail Fuel Survey Responses (2010–2015)

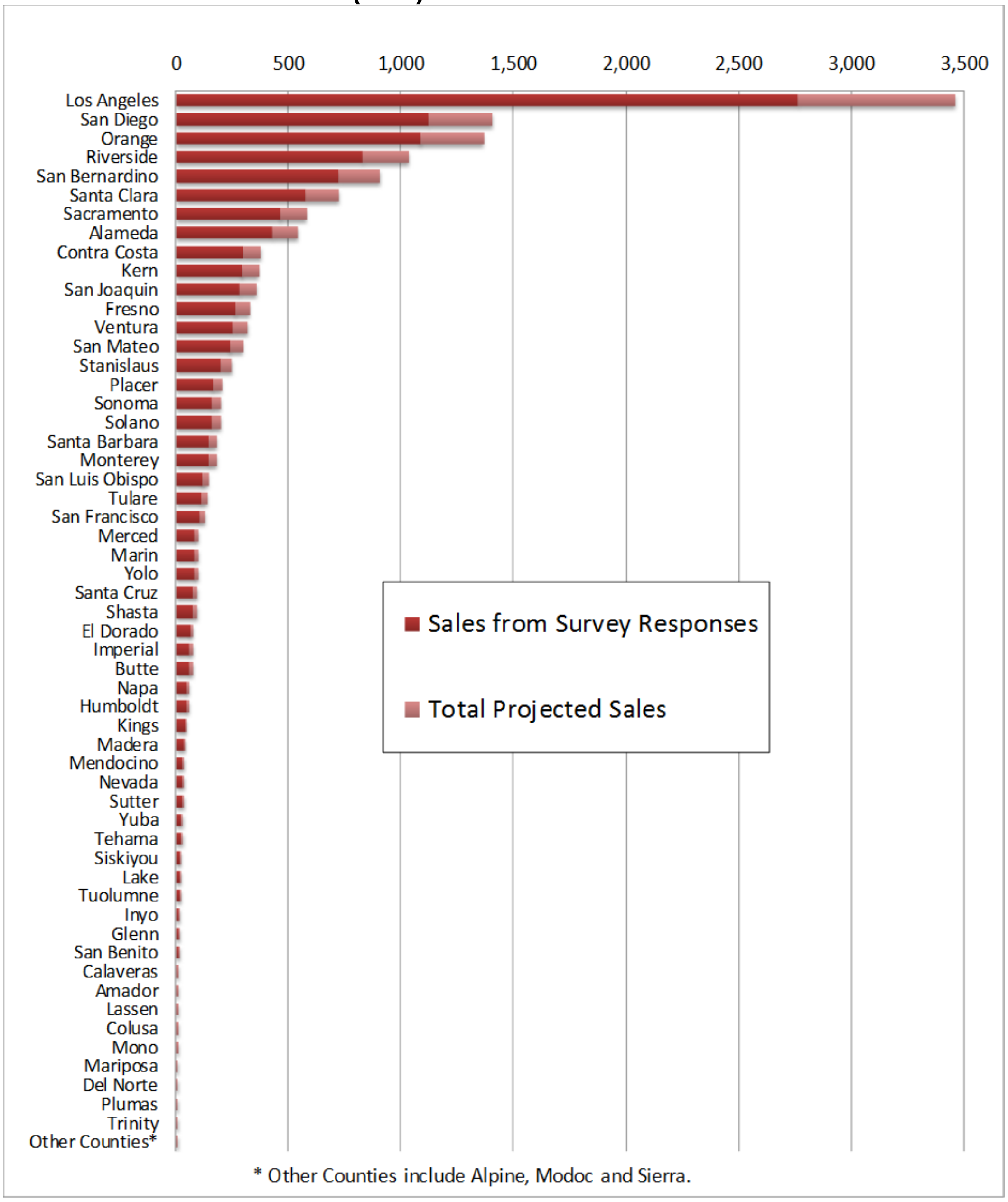
| Retail Fuel Station Counts - Survey Responses and Estimated Totals by County | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | | 2011 | | 2012[#] | | 2014[#] | | 2015[#] | |
| County | Survey Responses | Estimated Totals | Survey Responses | Estimated Totals | Survey Responses | Estimated Totals | Survey Responses | Estimated Totals | Survey Responses | Estimated Totals |
| Alameda | 275 | 338 | 293 | 341 | 298 | 371 | 203 | 309 | 239 | 309 |
| Amador | 19 | 23 | 20 | 23 | 22 | 27 | 17 | 26 | 17 | 22 |
| Butte | 80 | 98 | 84 | 98 | 80 | 100 | 64 | 97 | 76 | 98 |
| Calaveras | 23 | 28 | 23 | 27 | 21 | 26 | 20 | 30 | 19 | 25 |
| Colusa | 21 | 26 | 19 | 22 | 16 | 20 | 17 | 26 | 17 | 22 |
| Contra Costa | 224 | 276 | 237 | 276 | 234 | 291 | 175 | 266 | 196 | 253 |
| Del Norte | 12 | 15 | 11 | 13 | 11 | 14 | 9 | 14 | 9 | 12 |
| El Dorado | 53 | 65 | 61 | 71 | 61 | 76 | 48 | 73 | 54 | 70 |
| Fresno | 258 | 317 | 281 | 327 | 271 | 337 | 208 | 317 | 239 | 309 |
| Glenn | 18 | 22 | 19 | 22 | 17 | 21 | 16 | 24 | 17 | 22 |
| Humboldt | 68 | 84 | 73 | 85 | 70 | 87 | 46 | 70 | 64 | 83 |
| Imperial | 62 | 76 | 59 | 69 | 54 | 67 | 58 | 88 | 56 | 72 |
| Inyo | 22 | 27 | 23 | 27 | 20 | 25 | 18 | 27 | 20 | 26 |
| Kern | 274 | 337 | 280 | 326 | 282 | 351 | 236 | 359 | 252 | 326 |
| Kings | 48 | 59 | 49 | 57 | 46 | 57 | 41 | 62 | 45 | 58 |
| Lake | 35 | 43 | 34 | 40 | 29 | 36 | 28 | 43 | 27 | 35 |
| Lassen | 15 | 18 | 17 | 20 | 15 | 19 | 15 | 23 | 18 | 23 |
| Los Angeles | 1,590 | 1,956 | 1,645 | 1,914 | 1,580 | 1,966 | 1,377 | 2,097 | 1,464 | 1,893 |
| Madera | 50 | 62 | 54 | 63 | 54 | 67 | 44 | 67 | 44 | 57 |
| Marin | 57 | 70 | 57 | 66 | 55 | 68 | 35 | 53 | 50 | 65 |
| Mariposa | 17 | 21 | 20 | 23 | 18 | 22 | 12 | 18 | 16 | 21 |
| Mendocino | 51 | 63 | 57 | 66 | 48 | 60 | 38 | 58 | 42 | 54 |
| Merced | 71 | 87 | 81 | 94 | 75 | 93 | 66 | 100 | 78 | 101 |
| Mono | 18 | 22 | 18 | 21 | 12 | 15 | 16 | 24 | 17 | 22 |
| Monterey | 110 | 135 | 117 | 136 | 110 | 137 | 79 | 120 | 113 | 146 |
| Napa | 24 | 30 | 23 | 27 | 30 | 37 | 15 | 23 | 31 | 40 |
| Nevada | 35 | 43 | 36 | 42 | 34 | 42 | 23 | 35 | 34 | 44 |
| Orange | 537 | 661 | 546 | 635 | 528 | 657 | 472 | 719 | 494 | 639 |
| Placer | 101 | 124 | 110 | 128 | 111 | 138 | 89 | 136 | 106 | 137 |
| Plumas | 25 | 31 | 24 | 28 | 22 | 27 | 22 | 34 | 20 | 26 |
| Riverside | 402 | 495 | 418 | 486 | 420 | 523 | 380 | 579 | 425 | 549 |
| Sacramento | 302 | 372 | 311 | 362 | 298 | 371 | 209 | 318 | 276 | 357 |
| San Benito | 12 | 15 | 12 | 14 | 12 | 15 | 9 | 14 | 9 | 12 |
| San Bernardino | 428 | 527 | 452 | 526 | 444 | 552 | 394 | 600 | 436 | 564 |
| San Diego | 603 | 742 | 644 | 750 | 622 | 774 | 541 | 824 | 599 | 774 |
| San Francisco | 84 | 103 | 82 | 95 | 80 | 100 | 52 | 79 | 66 | 85 |
| San Joaquin | 176 | 217 | 186 | 216 | 183 | 228 | 144 | 219 | 186 | 240 |
| San Luis Obispo | 87 | 107 | 94 | 109 | 78 | 97 | 74 | 113 | 90 | 116 |
| San Mateo | 160 | 197 | 170 | 198 | 158 | 197 | 94 | 143 | 135 | 175 |
| Santa Barbara | 95 | 117 | 101 | 118 | 99 | 123 | 81 | 123 | 98 | 127 |
| Santa Clara | 310 | 381 | 329 | 383 | 316 | 393 | 239 | 364 | 287 | 371 |
| Santa Cruz | 68 | 84 | 70 | 81 | 70 | 87 | 44 | 67 | 66 | 85 |
| Shasta | 98 | 121 | 102 | 119 | 101 | 126 | 78 | 119 | 102 | 132 |
| Siskiyou | 35 | 43 | 32 | 37 | 36 | 45 | 22 | 33 | 37 | 48 |
| Solano | 115 | 141 | 133 | 155 | 121 | 151 | 82 | 125 | 99 | 128 |
| Sonoma | 121 | 149 | 116 | 135 | 110 | 137 | 93 | 142 | 104 | 134 |
| Stanislaus | 146 | 180 | 158 | 184 | 149 | 185 | 113 | 172 | 139 | 180 |
| Sutter | 32 | 39 | 35 | 41 | 29 | 36 | 25 | 38 | 30 | 39 |
| Tehama | 37 | 46 | 36 | 42 | 34 | 42 | 23 | 35 | 32 | 41 |
| Trinity | 17 | 21 | 17 | 20 | 12 | 15 | 13 | 20 | 16 | 21 |
| Tulare | 162 | 199 | 183 | 213 | 172 | 214 | 141 | 215 | 146 | 189 |
| Tuolumne | 28 | 34 | 28 | 33 | 30 | 37 | 23 | 35 | 27 | 35 |
| Ventura | 161 | 198 | 168 | 196 | 150 | 187 | 134 | 204 | 146 | 189 |
| Yolo | 52 | 64 | 51 | 59 | 50 | 62 | 44 | 67 | 52 | 67 |
| Yuba | 28 | 34 | 32 | 37 | 27 | 34 | 24 | 37 | 28 | 36 |
| Other Counties* | 13 | 16 | 12 | 14 | 13 | 15 | 11 | 17 | 11 | 14 |
| Total | 7,965 | 9,800 | 8,343 | 9,710 | 8,038 | 10,000 | 6,594 | 10,040 | 7,516 | 9,718 |

[#] 2012, 2014, and 2015 data are not directly comparable to other years since an improved methodology is used, but is within 5 percent compared to the previous methodology.

* Other Counties include Alpine, Modoc and Sierra.

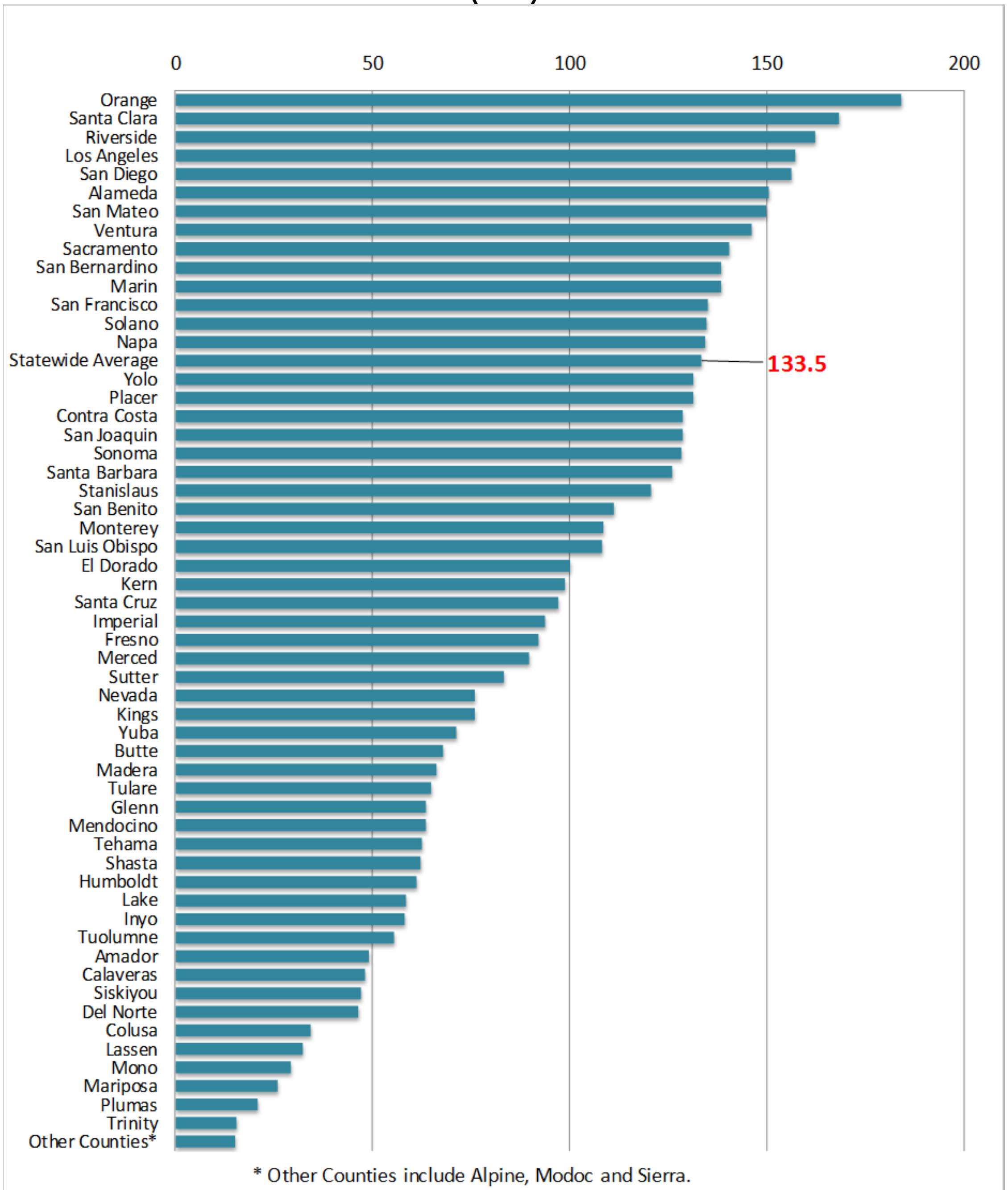
Source: Energy Commission

**Figure 65: California Gasoline Sales by County – Survey Responses and Projected Totals (2015) Millions of Gallons**




Source: Energy Commission

**Figure 66: California Average Monthly Gasoline Sales by Site—Thousands of Gallons (2015)**

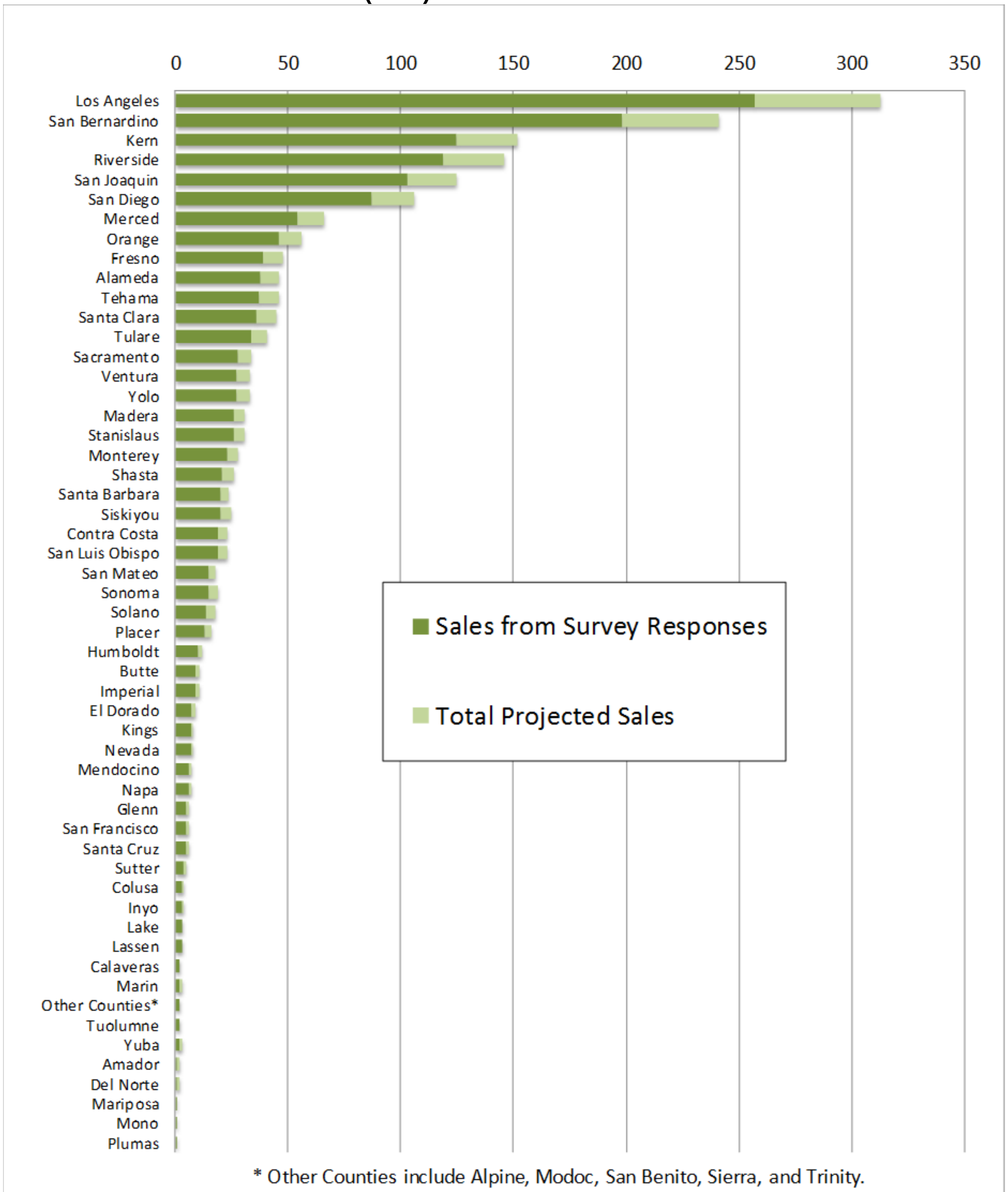



Source: Energy Commission

**Figure 67** ranks counties by diesel sales, both from report results and projected totals. Los Angeles is again the top county with total estimated diesel sales of 313 million gallons or 16.5 percent of state totals. Unlike gasoline, most of the top counties have significant agricultural activities (like Kern and San Joaquin). This relationship is more evident in **Figure 68,** where average diesel sales by site have Tehama County on top with 96,300 gallons per month. All of the counties above the statewide average of 17,700 gallons per month have heavy agricultural activity.

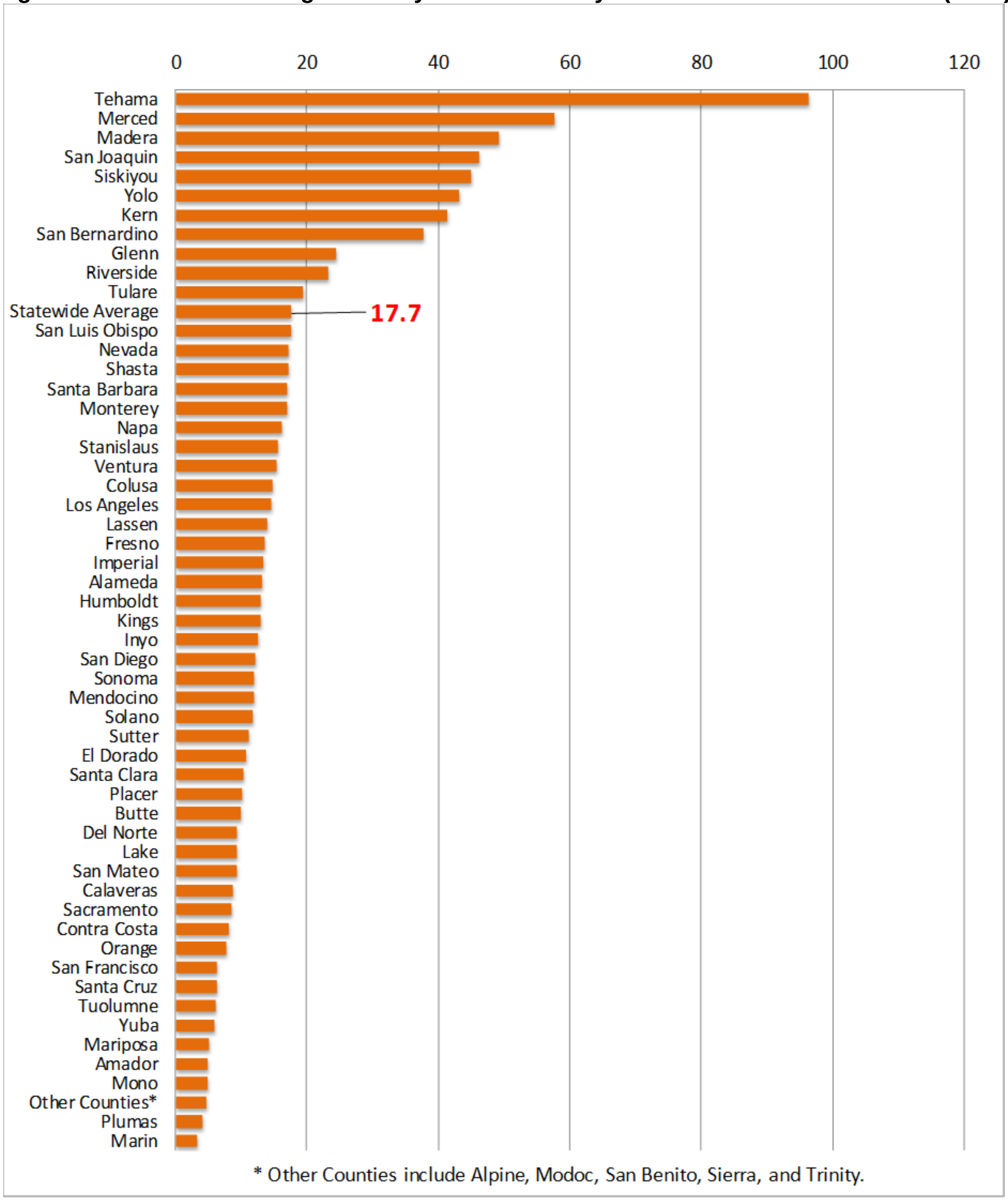
The diesel fuel sold at these retail stations is not dyed diesel as those sales are mainly at distribution terminals.

**Figure 67: California Diesel Sales by County – Survey Responses and Projected Totals (2015) Millions of Gallons**




Source: Energy Commission

**Figure 68: California Average Monthly Diesel Sales by Site – Thousands of Gallons (2015)**

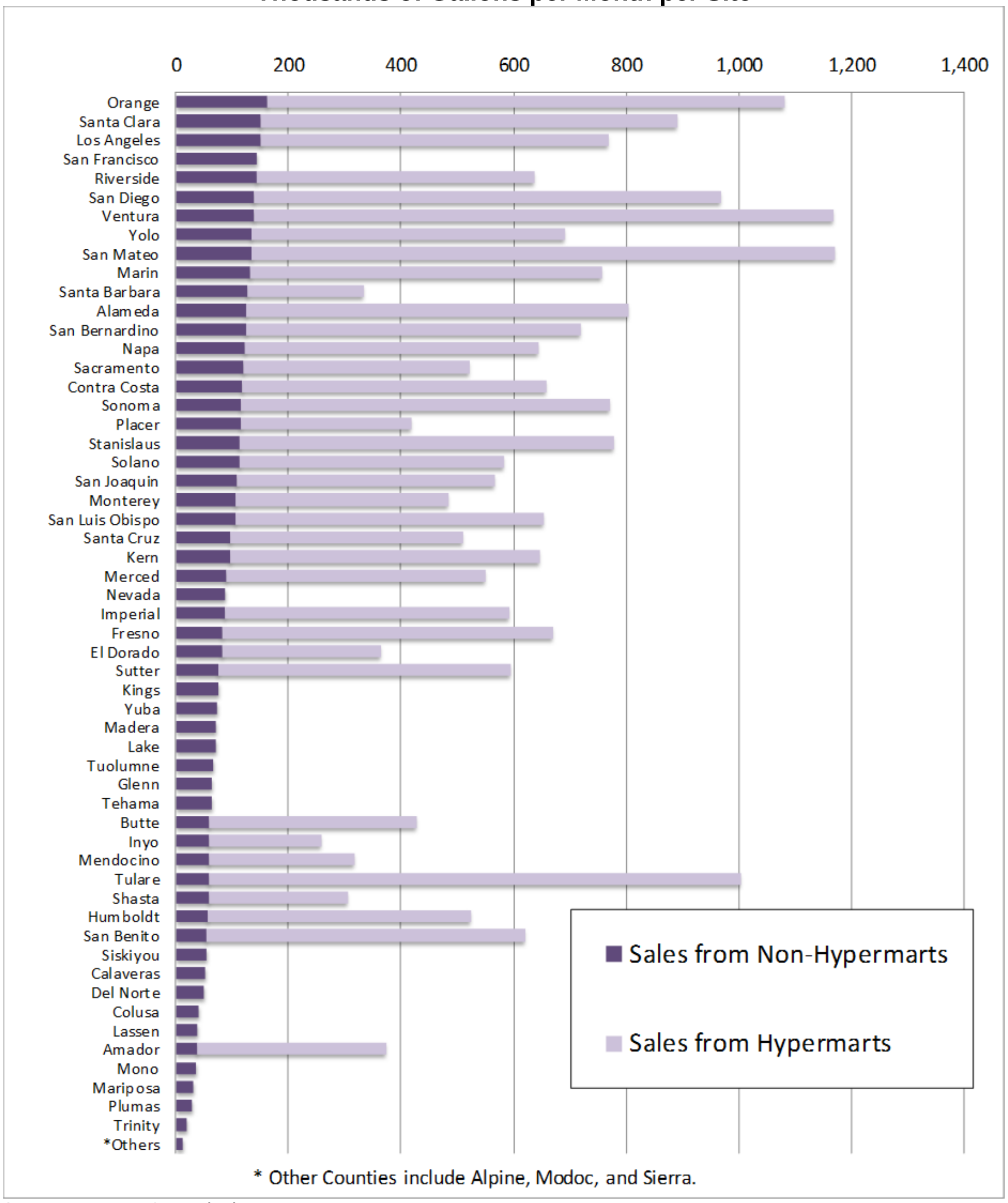



Source: Energy Commission.

**Figure 69** displays the average monthly gasoline sales for each county by hypermarket stores and all other fueling locations. The report results from 2015 show that there were 215 responding sites characterized as hypermarkets. Statewide gasoline sales for these locations amounted to 711,659 gallons per month, about 5.3 times greater than the statewide monthly average for all fueling locations. The greatest difference in average monthly gasoline sales is for Santa Cruz County where the hypermarkets monthly sales are more than 15 times greater than all of the other stations. The highest average sales by hypermarkets are 1.117 million gallons per month in San

Mateo County, followed by 1.169 million gallons per month in Ventura County. The significantly higher per store sales volumes allow hypermarket companies to operate with lower per-gallon margins compared to nonhypermarket locations, which is why these types of stores offer some of the lowest prices during periods of normal refinery operations.

**Figure 69: California Gasoline Sales by County—Nonhypermarts vs. Hypermarts (2015) Thousands of Gallons per Month per Site**




Source: Energy Commission

# California's Transportation Fuel Supply Issues

## Proposed Hydrofluoric Acid Alkylation Phaseout

The South Coast Air Quality Management District (SCAQMD) has proposed a rule that has the potential to eliminate a specific type of catalyst use at refineries with alkylation units, an important source of gasoline blending components. Proposed Rule 1410 (PR 1410) is in development and has three potential outcomes: no ban (maintain technology-neutral policy) performance-based structure, and ban of hydrofluoric (HF) acid.[44] HF is one of two types of compounds used as a catalyst in petroleum refinery alkylation process units around the world, including the United States and California. The other type of catalyst is sulfuric acid.[45] HF has the potential to volatilize into a toxic and corrosive low-level vapor cloud of hydrofluoric acid that can harm individuals that come into contact with it if released. Recognizing the impact of such a scenario, the SCAQMD in 1991 proposed eliminating HF alkylation by 1998.[46] Southern California refiners developed agreements with SCAQMD that resulted in the adoption of additional safety measures designed to decrease the possibility of a vapor cloud release if the HF was to breach containment.[47]

The only two refinery locations in California that have HF alkylation are Petroplus Holdings, Blackstone Group and First Reserve (PBF) in Torrance and Valero in Wilmington. Both facilities have modified HF safeguards in place. However, the PR 1410 includes the possibility that HF would be eliminated by some yet-to-be-determined deadline. If PR 1410 is approved by the end of 2017 with an HF ban, there could be a potential negative impact to transportation fuel supply for Southern California similar to or exceeding the price increase consequences observed following the ExxonMobil's Torrance refinery explosion on February 18, 2015, that ultimately translated to $5.6 billion in higher gasoline costs for California motorists and businesses. Gasoline prices were elevated by more than 56 cents per gallon at the peak and remained 26 cents per gallon higher than normal for 17 months, as described earlier in this chapter.

It is uncertain whether a duplicate alkylation unit could be constructed (using sulfuric acid) on site at either refining location such that the existing modified HF alkylation units can continue operating prior to shutdown and work to tie in the new sulfuric alkylation units. If there is an insufficient footprint for such a project, then the alternative would be to cease operations of the modified HF units, demolish the structure and appurtenances, and construct the new sulfuric

---

44 PR 1410 Working Group Meeting #1, April 19, 2017, slide number 23. A link to the presentation is as follows: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1410/mtg1-final.pdf?sfvrsn=6 A working group has been created as part of the PR 1410 development, including representatives from the refining industry, state refinery safety entities, local communities, environmental groups, and other stakeholders. The California Energy Commission is not a member of this working group. A list of the participants may be accessed at the following link. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1410/pr-1410-WG-roster.pdf?sfvrsn=32.

45 STRATCO® Alkylation Technology, DuPont, 2014 Worldwide Alkylation Capacity chart can be accessed at the following link: http://www.dupont.com/content/dam/dupont/products-and-services/consulting-services-and-process-technologies/consulting-services-and-process-technologies-landing/documents/STRATCO_Alkylation%20Technology.pdf.

The chart shows the various technology providers and the fact that nearly half of the global capacity utilizes HF.

46 PR 1410 Working Group Meeting #1, April 19, 2017, slide number 9.

47 Ibid., slide numbers 9, 15, and 16.

alkylation units in their place. This disturbance could take 18 to 24 months to complete after all necessary permits to perform the demolition and construction of the new process units are obtained. Recent examples of the Chevron Richmond Modernization Project and the Valero CBR permit request show that refinery projects can take years (nine years for the Chevron project) to work through the permit process and, in the case of Valero's project, can ultimately be denied.

If an HF ban were compelled, it is also uncertain if either or both companies would elect to make changes to their facilities. Costs of new alkylation units run in the hundreds of millions of dollars. A recent project approved for the Valero Houston refinery is estimated to cost $300 million for an alkylation unit with a capacity of 13,000 barrels per calendar day.[48] The capacity of the alkylation units at Valero Wilmington and PBF Torrance are 22,000 and 24,200 BPD capacity, respectively.[49] California requires nearly twice that capacity, meaning the potential costs at the two California refineries could approach or exceed $500 million per refinery. Estimated costs for a replacement project are at or near the value of the entire refinery when one considers that ExxonMobil sold the Torrance refinery to PBF Energy for $537.5 million.[50]

Potential impacts to transportation fuel markets of a potential HF ban were assessed in detail and presented by Stillwater Associates at the July 6, 2017, *Integrated Energy Policy Report* workshop.[51] That analysis concluded that the costs for replacing the HF alkylation units with new sulfuric acid alkylation units would be roughly $1.8 billion for the two refineries, higher than staff's estimate, in part due to the inclusion of acid regeneration facilities. The primary conclusions were:

- Alkylation is an important refining process. CARBOB cannot be produced by SoCal refineries without alkylate.
- Should HF be banned, it appears unlikely that impacted refiners would replace current process units due to the high cost.
- The impacted refineries are unlikely to be viable without alkylation.
- Should the impacted refineries cease operations, 25 percent of regional demand would have to be imported.
- With only three fuels refiners left in SoCal, the market will have less competition.
- Offshore refiners will produce the products and ship them half way around the world to the California market.

48 Valero Energy Reports First Quarter 2016 Results. A link to the article is as follows: http://www.investorvalero.com/phoenix.zhtml?c=254367&p=irol-newsArticle&id=2164174.

49 *Refinery Capacity Report*, U.S. EIA, June 2016, Table 4, pages 27-28. A link to the report is as follows. https://www.eia.gov/petroleum/refinerycapacity/refcap16.pdf.

50 "ExxonMobil Sells Torrance Refinery for More Than $530 Million," *Daily Breeze*, September 30, 2015. A link to the article is as follows. http://www.dailybreeze.com/business/20150930/exxonmobil-sells-torrance-refinery-for-more-than-530-million.

51 "Impact of an HF Ban on Southern California Transportation Fuels Supply, "Stillwater Associates, July 6, 2017. A link to the presentation is as follows: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN220048_20170705T151140_Impact_of_an_HF_Ban_on_Southern_California_Transportation_Fuels.pdf.

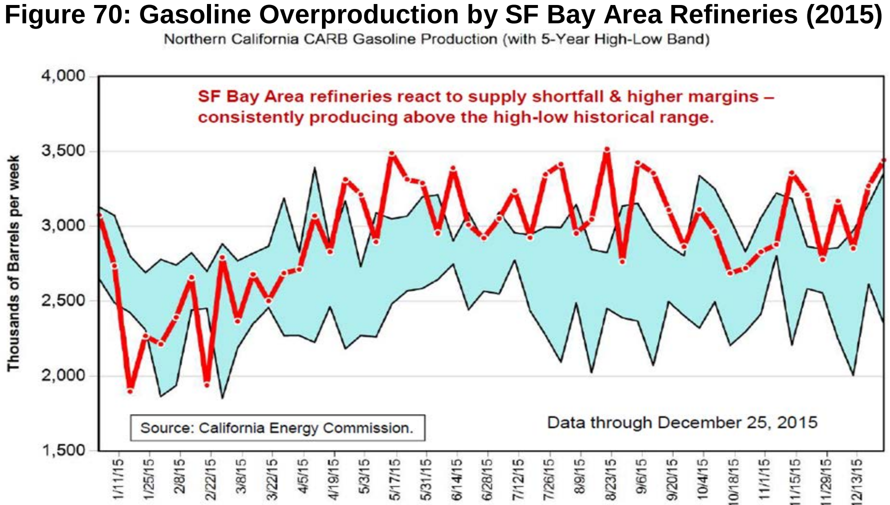
- As a result, average spot prices could rise $0.25 per gallon or more and, ultimately, the California consumer would pay the price.

## Proposed San Francisco Bay Area Refinery Greenhouse Gas Limits

The BAAQMD has recently revised a proposed rule, referred to as Regulation 12, Rule 16 [52] that is designed to limit greenhouse gas (GHG) emissions for refineries operating in the greater San Francisco Bay Area. If approved by the district board, the regulation is scheduled to be in effect by January 1, 2018.[53] The concern is the potential impact GHG caps could have on the ability of Bay Area refineries to respond to temporary supply imbalances created by significant unplanned refinery outages. This regulation was proposed on May 31, 2017, and on June 26, 2017, the BAAQMD board voted to delay adoption of these regulations due to insufficient discussion.

As discussed earlier, part of the response to the ExxonMobil ESP explosion and subsequent reduction in gasoline production capacity was for other refiners to operate their facilities at higher levels to increase gasoline output above the normal ranges. **Figure 70** shows how refineries in Northern California consistently produced gasoline from one week to the next that was above their historical five-year high-low production band in response to this event.[54]

**Figure 70: Gasoline Overproduction by SF Bay Area Refineries (2015)**




Source: Energy Commission

To what extent the proposed regulation, if approved, could impact refinery operational flexibility depends on how low the caps are set relative to peak refinery transportation fuel production

---

52 *Regulation 12, Rule 16: Petroleum Refining Greenhouse Gas Emissions Limits*, Bay Area Air Quality Management District, Revised Final Staff Report, June 2017. A link to the report is as follows: http://www.baaqmd.gov/~/media/dotgov/files/rules/regulation-12-rule-16/documents/20170606_rsr_-final_1216-pdf.pdf?la=en.

53 *Regulation 12, Miscellaneous Standards of Performance, Rule 16, Petroleum Refining Greenhous Gas Emissions Limits*, Bay Area Air Quality Management District, June 7, 2017, section 12-16-301, page 12-16-3. A link to this document is as follows: http://www.baaqmd.gov/~/media/dotgov/files/rules/regulation-12-rule-16/documents/20170606_rpr_1216-pdf.pdf?la=en.

54 *California Transportation Fuels Market Refinery Turmoil – A Year in Review*, California Energy Commission, September 7, 2016, slide 19. A link to this presentation is as follows: http://docketpublic.energy.ca.gov/PublicDocuments/15-PMAC-01/TN214579_20161129T153522_California_Transportation_Fuels_Market_Refinery_Turmoil__A_Year.pptx.

periods. However, the need for such refinery-specific GHG cap limits could be diminished for two reasons.

1) It is highly improbable that the carbon intensity of crude oil used by refiners will worsen significantly from near-term conditions based on operational limitations and preferred envelope of properties for crude oil processed at refineries.
2) CARB has regulations in place that ensure any increased carbon intensity of crude oil used by refiners would be offset, keeping potential increased crude oil-related carbon intensity in check. (This requirement is part of that agency's LCFS.)

**Figure 71** is a plot of two crude oil properties (sulfur and API gravity or density) between 2006 and 2015. API gravity is a measure of density or how heavy the crude oil is from one year to the next. The API gravity formula has an inverse relationship to density, meaning the higher the API number, the lower the density of the crude oil. As the chart shows, the average crude oil properties for all of the SF Bay Area refineries combined has become slightly lighter in density and slightly higher in sulfur content.

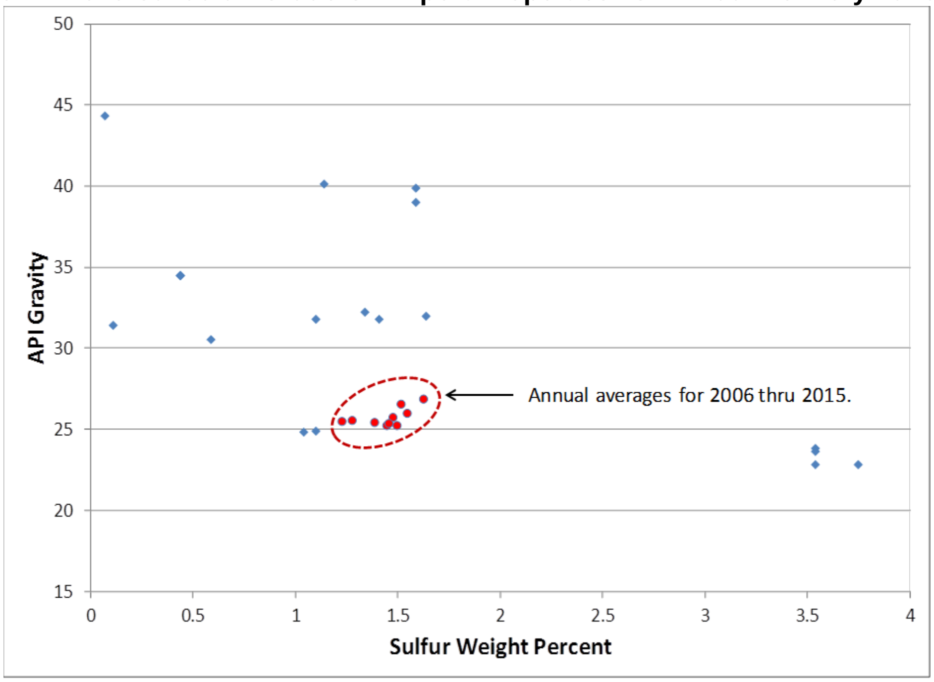
**Figure 71: SF Bay Area Refineries—Crude Oil Properties (2006–2015)**


Source: Energy Commission analysis of PIIRA data

Refiners receive crude oil from many sources, both foreign and domestic. As a general practice, refiners blend various types of crude oil together before processing for maintaining a steady overall quality of crude oil that helps control refinery operations and regulate the different ratios and types of transportation fuels produced from one month to the next.

Although the year-to-year variability of the average sulfur and density properties does shift, the degree of change is rather modest when the scale is adjusted to include properties of various types of Canadian crude oil processed in California, as shown in **Figure 72**. The majority of Canadian crude oils received by Bay Area refineries during 2015 were far outside the envelope of annual average blended properties. A meaningful shift to a much lighter or heavier usage of these types of crude oils would not be feasible without significant modifications to existing refineries, absent any deleterious impacts on refined product slate and economics.

**Figure 72: 2015 Canadian Crude Oil Import Properties vs. Annual Refinery Variability**



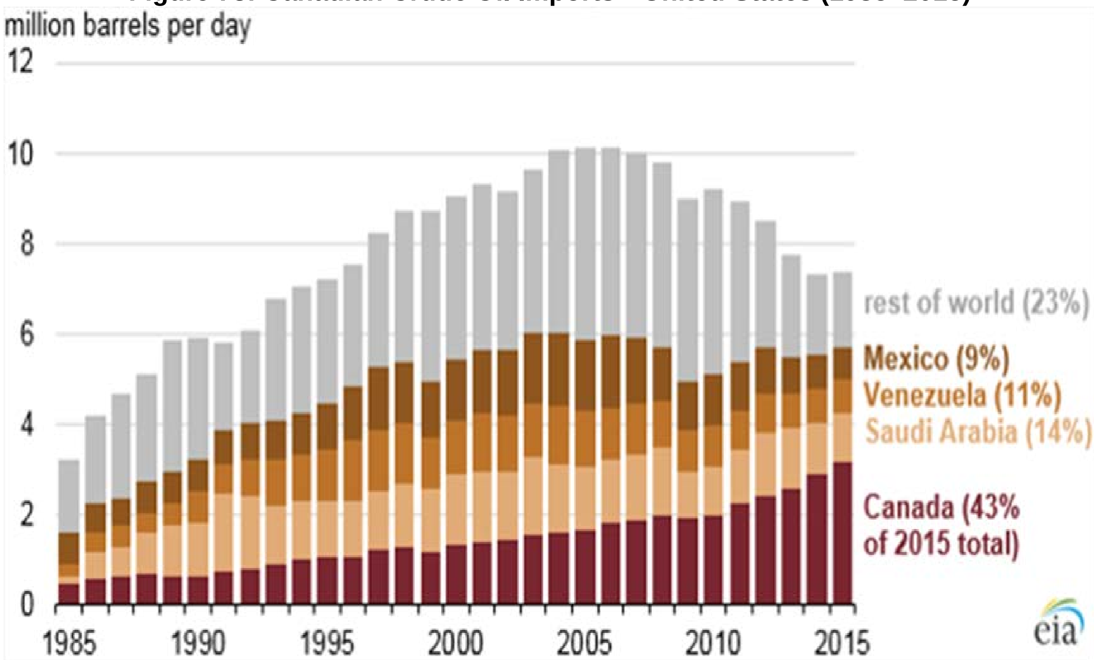

Source: Energy Commission analysis of PIIRA and U.S. EIA data

## Canada Crude Oil Trends

Trends for Canadian crude oil imports vary by region. For the United States, imports of crude oil from Canada have been rising as the United States is a natural destination for higher Canadian crude oil production due to the proximity of refining customers and the adequacy of infrastructure to deliver the crude oil across the border. **Figure 73** shows the breakdown of U.S. crude oil imports from 1985 to 2015. The resurgence of domestic oil production has diminished the need for imports. However, Canadian oil imports continue to rise as Canada's output grows such that the United States imported a record 43 percent of its total foreign imports from this country.

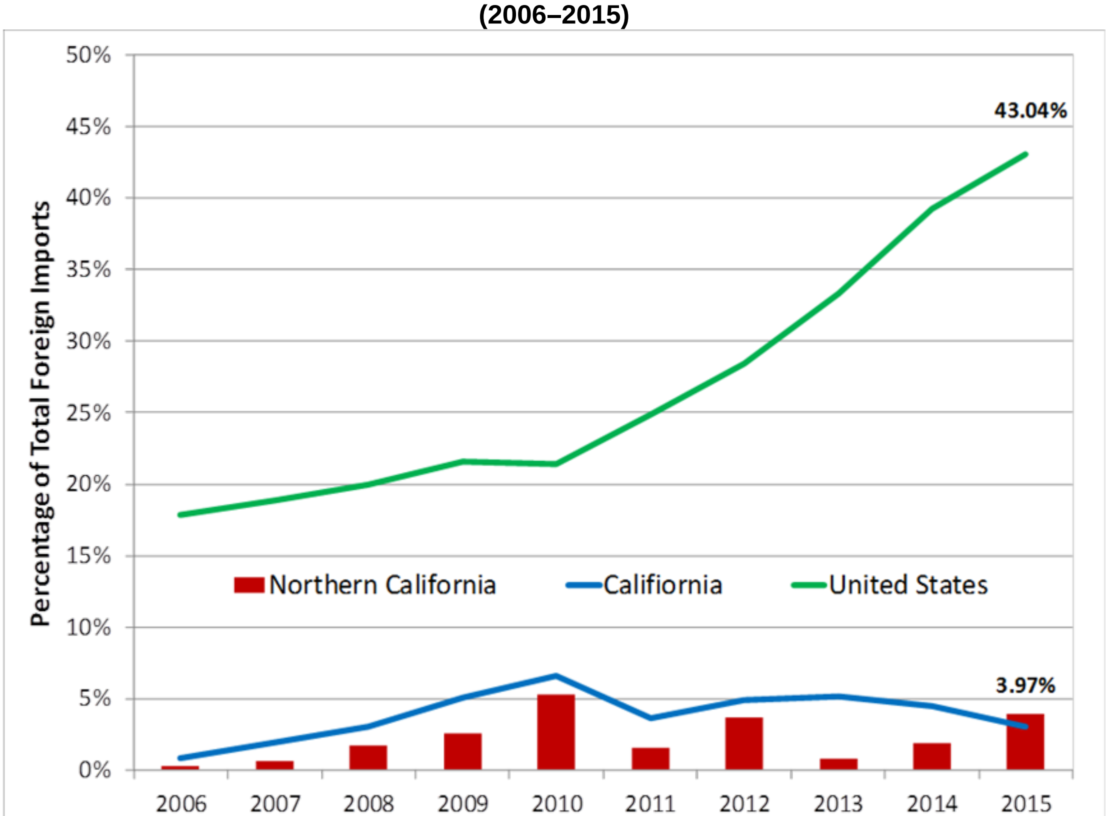
**Figure 74** illustrates that contrary to the national trend, California refiners have not been increasing their collective usage of Canadian crude oils. If anything, the trend appears to be somewhat flat or even declining since 2010. Bay Area refiners use a consistently lower portion than the statewide average, except for 2015.

**Figure 73: Canadian Crude Oil Imports—United States (1985–2015)**




Source: U.S. EIA

**Figure 74: Canadian Crude Oil Imports—California and San Francisco Bay Area (2006–2015)**




Source: U.S. EIA

## Reduced Sulfur Levels in Marine Bunker Fuels

The International Maritime Organization (IMO) oversees the development and standards designed to reduce harmful emissions to the environment from shipping. As part of these efforts, an international convention was adopted in 1997 specifically designed to reduce air pollution from marine vessels on a global scale, referred to as the MARPOL Convention. Part of Annex VI to this convention is designed to decrease emissions of oxides of sulfur ($SO_x$) from marine vessels by limiting the amount of sulfur that exists in the primary transportation fuel referred to as *bunker fuel*. The target level is for all bunker fuels to limit sulfur content to no more than 0.50 percent by weight by January 1, 2020. The concern is that lower sulfur limits may be met, at least initially, by blending ultra-low-sulfur CARB diesel fuel with other distillates, thus placing an additional demand on diesel fuel for California. The potential incremental demand for CARB diesel has not been quantified at this time. **Table 9** shows how the global sulfur limits have been reduced, including other regions of the world that have already seen sulfur reduction limits put in place for Emission Control Areas (ECA).[55]

**Table 9: Annex VI Sulfur Limits and Deadlines**

| Outside an ECA established to limit SOx and particulate matter emissions | Inside an ECA established to limit SOx and particulate matter emissions |
|---|---|
| 4.50% m/m prior to 1 January 2012 | 1.50% m/m prior to 1 July 2010 |
| 3.50% m/m on and after 1 January 2012 | 1.00% m/m on and after 1 July 2010 |
| 0.50% m/m on and after 1 January 2020* | 0.10% m/m on and after 1 January 2015 |

* depending on the outcome of a review, to be concluded by 2018, as to the availability of the required fuel oil, this date could be deferred to 1 January 2025. MEPC 70 (October 2016) considered an assessment of fuel oil availability to inform the decision to be taken by the Parties to MARPOL Annex VI, and decided that the fuel oil standard (0.50% m/m) shall become effective on 1 January 2020 (resolution MEPC.280(70)).

The ECAs established are:

1. Baltic Sea area – as defined in Annex I of MARPOL ($SO_x$ only);
2. North Sea area – as defined in Annex V of MARPOL ($SO_x$ only);
3. North American area (entered into effect 1 August 2012) – as defined in Appendix VII of Annex VI of MARPOL ($SO_x$, $NO_x$ and PM); and
4. United States Caribbean Sea area (entered into effect 1 January 2014) – as defined in Appendix VII of Annex VI of MARPOL ($SO_x$, $NO_x$ and PM).

Source: International Maritime Organization

Marine vessels operating off the coast of California have had to comply with an even lower 0.10 percent sulfur limit for bunker fuel consumed within the North American ECA since January 2015. But the volume of bunker fuel distributed to marine vessels in the Ports of Los Angeles, Long Beach, and Oakland that meets this standard is a subset of all bunker fuel sales that can have the higher sulfur content of 3.50 percent by weight because the marine vessel operators are

55 *Sulphur oxides (SOx) – Regulation 14*, International Maritime Organization. A link to this information is as follows: http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Sulphur-oxides-(SOx)-%E2%80%93-Regulation-14.aspx.

allowed to burn the other higher-sulfur bunker fuels once they depart the ECA zone. It is not known what portion of bunker fuel sales meets the 0.10 percent sulfur limit. By January 2020, all the non-ECA bunker sales would need to comply by dropping the sulfur limits from the current 3.50 percent to 0.50 percent by weight. However, enforcement provisions for the standard may not be sufficient to deter cheating, as raised by David Hackett, president of Stillwater Associates.[56]

A recent study on the ability of the industry to meet the new standards was released in July 2016. The primary 2020 global refinery production projection conclusion of the *CE Delft Study* is depicted in **Table 10**.[57] However, not all stakeholders are convinced this assessment has been conducted in a sound manner. The Turner Mason company has reviewed this study and notes a number of concerns that call into question the overall conclusion that the refining sector will be able to adjust by the deadline.[58] A deadline for the final decision on adequacy of lower sulfur bunker fuels is scheduled for 2018. If the MARPOL Convention participants conclude that sufficient supplies of lower sulfur bunker fuel will not be available by January 2020, the compliance deadline can be extended to 2025.

**Table 10: Global Refinery Production (2012 vs. 2020)**

| | Production in 2012 | Production in 2020 |
|---|---|---|
| Gasoline | 963 | 1,086 |
| Naphtha | 256 | 305 |
| Jet/Kero Fuel | 324 | 331 |
| Middle Distillate | 1,316 | 1,521 |
| MGO | 64 | 39 |
| Total Marine Heavy Fuel Oil (HFO) | 228 | 269 |
| Marine HFO (S≤ 0.5% m/m) | 0 | 233 |
| Marine HFO (S> 0.5% m/m) | 228 | 36 |
| LPG | 113 | 110 |
| Other | 784 | 537 |
| Total | 3,984 | 4,159 |

Note: The main result of the assessment is that in all scenarios the refinery sector has the capability to supply sufficient quantities of marine fuels with a sulfur content of 0.5% m/m or less and with a sulfur content of 0.1% m/m or less to meet demand for these products, while meeting demand for nonmarine fuels.

Source: CE Delft\.

Compliance with the regulation can also be achieved through other means such as:

- Installing scrubbers to take $SO_x$ exhaust emissions below the standard.
- Retrofitting ship engines to run on lower-sulfur fuels such as natural gas.

56 *IMO 2020: The Next Big Thing for the Oil Supply Chain*, David Hackett, Stillwater Associates, May 1, 2017. A link to this article is as follows: http://stillwaterassociates.com/imo-2020-the-next-big-thing-for-the-oil-supply-chain/.

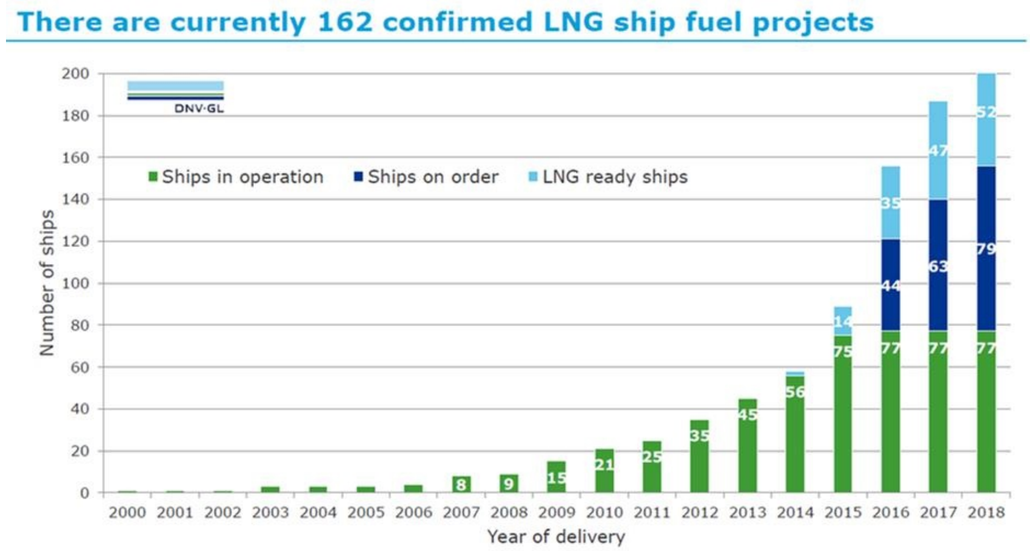
57 *Assessment of Fuel Oil Availability*, Final Report, CE Delft, July 2016. A link to the site that provides access to the report is as follows: http://www.cedelft.eu/publicatie/assessment_of_fuel_oil_availability/1858.

58 *"Don't Worry, Be Happy" – An Independent Look at the CE Delft Report*, Turner Mason, October 17, 2016. A link to the article is as follows: http://www.turnermason.com/index.php/dont-worry-be-happy-an-independent-look-at-the-ce-delft-report/.

- Building new marine vessels with dual-fuel capability or natural gas engines only.

The *CE Delft Report* provides a projection for LNG fuel use by marine vessels by 2020, forecasting 175 marine vessels will operate in this configuration.[59] **Figure 75** provides an annual accounting of existing LNG-powered marine vessels, forecasted number of new LNG-fueled marine vessels under construction or on order, and number of LNG conversions.[60]

**Figure 75: Existing Fleet of LNG-Fueled Marine Vessels and New Builds (2000–2018)**




Source: DNV GL

**Figure 75** excludes inland waterway vessels and LNG carriers that use a very small portion of their cargo to fuel their marine engines. Adrian Tolson of 2020 Marine Energy provided a detailed assessment of the IMO 2020 standards and potential outlook for California during the July 6 IEPR workshop.[61] Tolson's main conclusions are:

- There will be no extension of the deadline beyond 2020.
- California low-sulfur bunker demand will be met with producing partial lower-sulfur bunker fuel, blending with ultra-low-sulfur diesel fuel, and changing refinery blending operations.
- Decreased local sales of bunker fuels are due to increased competition with Asia.

---

59 *Assessment of Fuel Oil Availability*, Final Report, CE Delft, July 2016, Annex E, LNG Demand Projections, pages 175-183. A link to the site that provides access to the report is as follows: http://www.cedelft.eu/publicatie/assessment_of_fuel_oil_availability/1858.

60 *DNV GL – LNG Fueled Vessels Ship list – Vessels in Operation and Vessels on Order*, DNV GL, March 21, 2016, slide 8. A link to the site to obtain a copy of this presentation is as follows: https://www.dnvgl.com/maritime/lng/ships.html.

61 *IMO Marine Fuel Regulations*, 2020 Marine Energy, July 6, 2017. A link to the presentation is as follows: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN220061_20170706T092046_IMO_Marine_Fuel_Regulations.pdf.

# Chapter 4:
# Renewable and Alternative Fuels

Use of renewable and other alternative fuels in the United States and California is expected to continue growing, primarily as a consequence of federal and state regulations mandating ever-increasing levels of renewable content in gasoline and diesel fuel, carbon reduction rules, and incentives for increasing alternative fuel consumption. However, there are several unresolved issues regarding adequacy of both additional supplies and the requisite infrastructure to receive and distribute increased quantities of ethanol and biodiesel to California consumers. Likewise, there are numerous challenges to developing adequate vehicle production and sales, refueling infrastructure, and technical standards that would enable increased use of natural gas, electric, and other alternative fuels in transportation. This chapter will focus on ethanol, biodiesel, and renewable diesel supply issues.

## Ethanol Supply Outlook

Ethanol (normally referred to as denatured fuel ethanol) has a long history as a transportation fuel in the United States. The Ford Model T, first manufactured in 1908, was designed with an engine that operated on gasoline, kerosene, or ethanol.[62]

The use of ethanol as a motor vehicle fuel was modest from the early 1900s through the late 1930s. Declining prices of gasoline, relative to ethanol, decreased ethanol's role in transportation fuel for the next several decades until the oil price shocks of the 1970s spurred government action and intervention.[63] Federal assistance in the form of tax credits and loan guarantees resulted in a resurgence of the United States ethanol industry from "practically zero" in 1978 to more than 210 million gallons by 1982.[64] **Figure 76** shows the annual progression of ethanol production in the United States between 1979 and 2016.[65] Output reached a record 15.3 billion gallons during 2016 attributed to rising gasoline demand and the profitability of export markets outside of the United States.

Beginning in 1980, ethanol's use for blending in gasoline at concentrations of 10 percent by volume, referred to as E10 or gasohol, began to gain acceptance in somewhat limited quantities. However, further action by Congress mandated increased use of ethanol to help reduce formation of carbon monoxide beginning in November 1992 via the Wintertime Oxygenate Program

---

62 Wikipedia, "Ford Model T"; available at http://en.wikipedia.org/wiki/Ford_Model_T.

63 U.S. General Accounting Office, *Importance and Impact of Federal Alcohol Fuel Tax Incentives*, GAO/RCED-84-1, Washington D.C.: Government Printing Office, June 1984, page 1. http://archive.gao.gov/d6t1/124476.pdf.

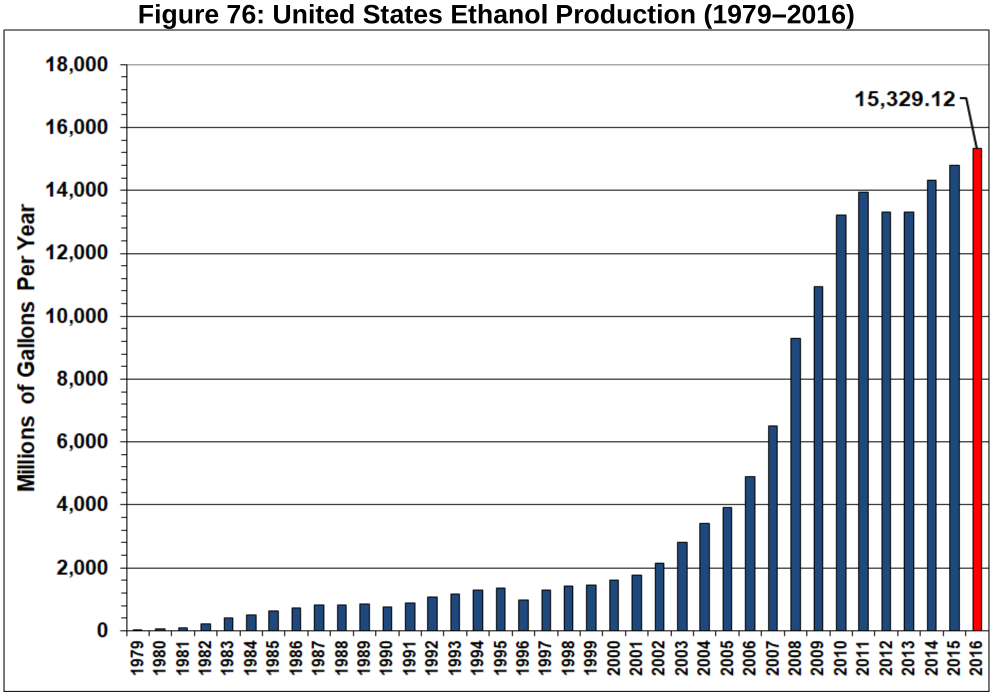
64 Ibid, page 1.

65 Ethanol production data from 1981 through 2016 obtained from the U.S. EIA (EIA). http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOOXE_YOP_NUS_1&f=M

Estimates of ethanol production prior to 1981 obtained from various sources published by the U.S. Department of Agriculture (USDA).

administered by the U.S. EPA.[66] Beginning in January 1995, federal reformulated gasoline regulations took effect that required year-round use of oxygenates (chemicals containing oxygen that are added to fuels, especially gasoline, to make them burn more efficiently) in roughly one-third of the nation's gasoline.[67] The CARB-adopted reformulated gasoline regulations specific to California required all gasoline sales to meet the new standard beginning March 1, 1996.[68] Oxygenates for these federal and state programs included ethers (such as MTBE and Tertiary Amyl Methyl Ether (TAME) and ethanol). The majority of the industry elected to use MTBE, but ethanol was used to blend with a portion of the wintertime oxygenated and reformulated gasoline markets. By the end of the 1990s, ethanol demand in the United States had increased to 1.4 billion gallons per year.

**Figure 76: United States Ethanol Production (1979–2016)**




Sources: USDA and U.S. EIA.

The phase-out of MTBE (due to groundwater contamination concerns) and passage of the Renewable Fuel Standard (RFS) are the events that resulted in a further expansion of ethanol use as a transportation fuel. The transition to ethanol and away from MTBE began in California following Governor Gray Davis' decision to eliminate MTBE's use, due to concerns of potential

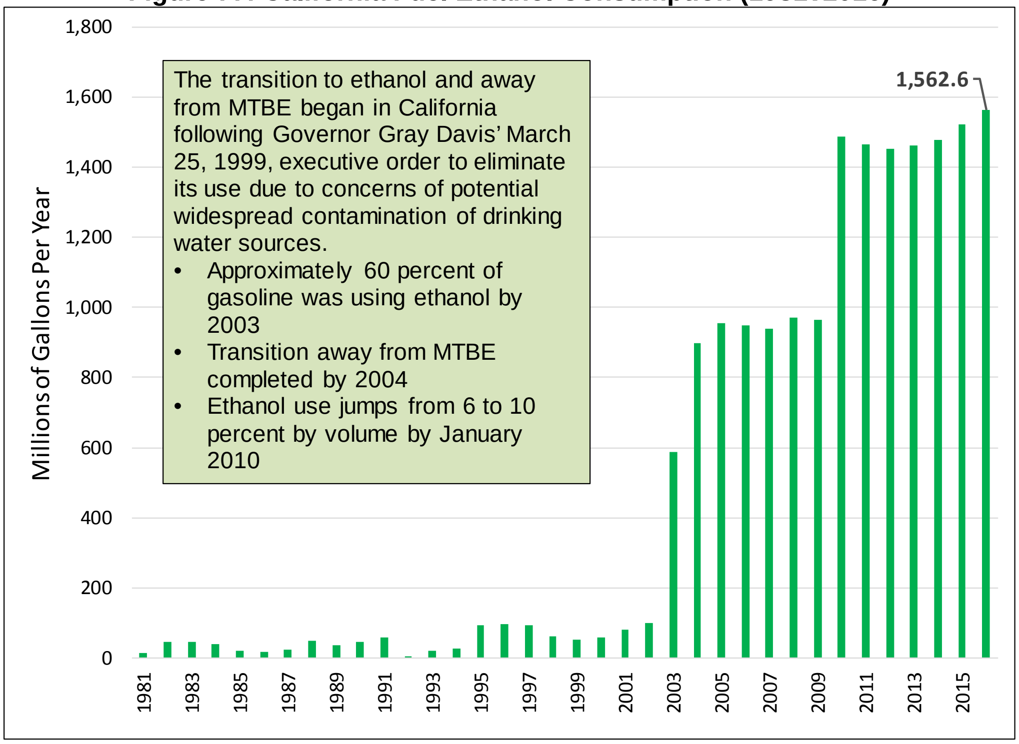
66 The federal requirement was one of the programs contained in the 1990 Clean Air Act Amendments. The California Air Resources Board promulgated regulations to meet compliance with the winter oxygenate program. A review of that program is summarized in: *An Overview of the Use of Oxygenates in Gasoline*, California Air Resources Board, September 1998. http://www.arb.ca.gov/fuels/gasoline/pub/oxyrprt.pdf.

67 The U.S. Environmental Protection Agency published the Final Rule for their reformulated gasoline regulations in the Federal Register on February 16, 1994 (59 FR 7716). Roughly 70 percent of California's gasoline sales were estimated to occur within the mandated federal reformulated gasoline (RFG) geographic regions of the state. https://www.gpo.gov/fdsys/pkg/FR-1994-02-16/html/94-20.htm.

68 The California Air Resources Board adopted reformulated gasoline regulations on November 22, 1991, referred to as CaRFG Phase 2 regulations. http://www.arb.ca.gov/fuels/gasoline/carfg2/carfg2.pdf.

widespread contamination of drinking water sources.[69] The practice of reducing use of MTBE spread to other areas of the country and by January 2005 the transition away from MTBE was completed, leaving ethanol as the only viable oxygenate. **Figure 77** shows consumption of ethanol in California since 1981.

**Figure 77: California Fuel Ethanol Consumption (1981v2016)**




Sources: United States Federal Highway Administration (U.S. FHA), BOE, and Energy Commission analysis.

Congress expanded ethanol's use by initially mandating minimum levels of blending through the RFS provisions of the Energy Policy Act of 2005, followed by an increase of these mandated levels through specific provisions of Energy Independence and Security Act (EISA). These federal mandates in conjunction with California's LCFS are expected to compel increased quantities of ethanol and biodiesel use in California over the next several years, including a longer-term move to renewable hydrocarbons that will begin to displace a portion of the gasoline and diesel fuel used for transportation.

---

69 Governor Davis issued Executive Order D-5-99 on March 25, 1999, directing various state agencies to develop regulations to eliminate the use of MTBE in California. Part of that order directed the California Energy Commission to "develop a timetable for the removal of MTBE from California gasoline not later than December 31, 2002." http://www.arb.ca.gov/fuels/gasoline/carfg3/eod0599.pdf

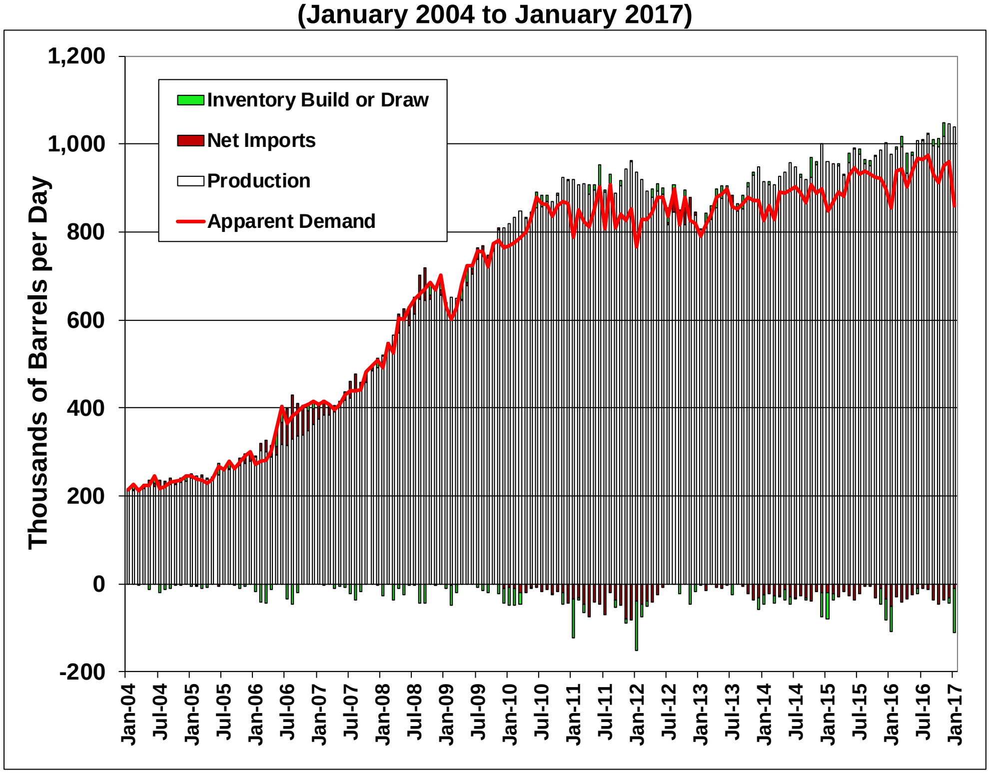
On July 1, 1999, the Energy Commission issued its report, *Timetable for the Phaseout of MTBE From California's Gasoline Supply*, which found that the phase-out deadline of December 31, 2002, could not be advanced. http://energyarchive.ca.gov/mtbe/documents/1999-07-01_300-99-003.PDF

Additional analysis by the Energy Commission and consultants working for the Energy Commission determined that the original phase-out deadline should be extended an additional year. As a consequence of this new analysis and other sources of information, Governor Davis issued Executive Order D-52-02 on March 14, 2002, delaying the final MTBE phase-out deadline until January 1, 2004. http://www.calgasoline.com/EOD52-02.PDF

## United States Ethanol Supply

Increasing demand for ethanol as a transportation fuel has been met by expansion of domestic production capacity, fluctuating quantities of imported ethanol, and inventory build or draws as necessary to balance out demand. **Figure 78** shows supply and demand for United States ethanol between January 2004 and January 2017. Ethanol demand set a record in August 2016, of 974 thousand BPD.[70] The demand for ethanol is expected to fluctuate, mirroring gasoline demand, as the average concentration of ethanol stays at or near 10 percent by volume.

**Figure 78: United States Ethanol Supply and Demand (January 2004 to January 2017)**




Sources: U.S. EIA and Energy Commission analysis.

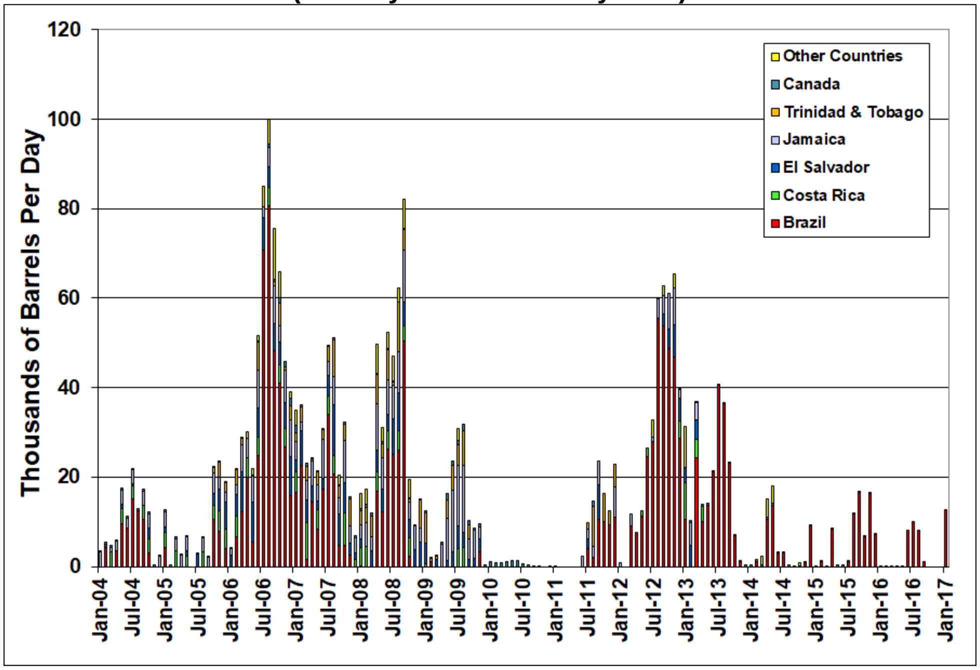
As **Figure 78** indicates, net imports of ethanol since mid-2010 have usually been negative (an indication that exports exceeded imports for a particular month) as the United States has become a large exporter due to excess domestic supply and low prices relative to export destinations. Foreign sources of ethanol (from Brazil and Caribbean Basin Initiative countries) are expected to play a more pivotal role as demand for ethanol with lower carbon intensity grows in response to the California LCFS and the Renewable Fuel Standard 2 (RFS2) Advanced Biofuels requirements. **Figure 79** shows monthly United States imports of ethanol between January 2004 and January 2017.[71]

---

70 Apparent demand for ethanol is calculated by summing production and imports, subtracting exports and adjusting for changes in inventory levels. The U.S. EIA is the source for the data. http://www.eia.gov/dnav/pet/pet_pnp_oxy_dc_nus_mbbl_m.htm. A link to the monthly fuel ethanol inventory data is http://www.eia.gov/dnav/pet/pet_stoc_typ_d_nus_SAE_mbbl_m.htm.

71 Data is sourced from EIA's Imports by Country of Origin information. http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epooxe_im0_mbbl_m.htm

Figure 79: United States Ethanol Imports
(January 2004 to January 2017)

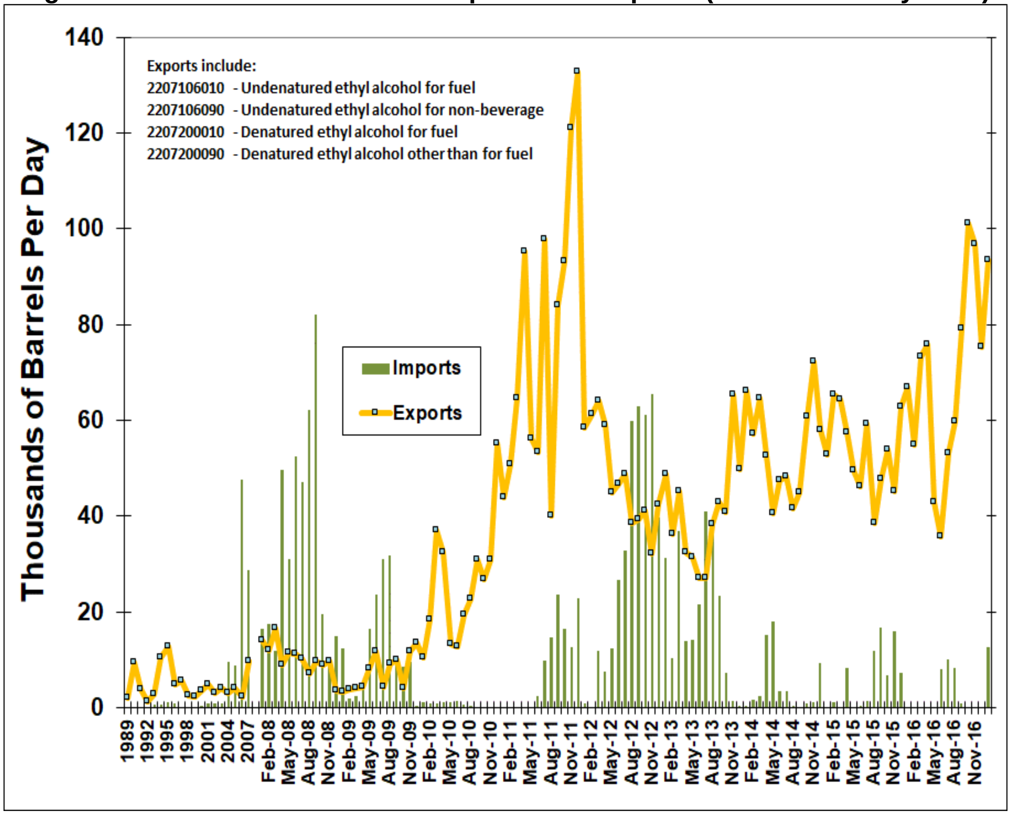



Sources: U.S. EIA and Energy Commission analysis.

Ethanol imports peaked at 100 thousand BPD during August 2006. The oversupply of domestic ethanol and relatively low prices in the United States resulted in declining ethanol imports over the last three years. Most recently the predominant source country has been Brazil, a product of sugarcane ethanol's lower carbon intensity value. Although imports have been declining, the quantity from Brazil is expected to rise over the next several years as obligated parties under the LCFS and RFS seek out this type of ethanol to help them achieve compliance with those state and federal requirements. While imports have dropped, the trend for ethanol exports has been one of growth since the summer of 2013 (see **Figure 80**).[72] Exports during 2016 averaged 68.0 thousand BPD, short of the record 77,800 BPD experienced during 2011. Although total exports for 2016 did not set a record, the relatively minor quantities of ethanol imports resulted in the United States reaching a near record 65,600 BPD of net exports, second only to the 2011 quantity of 69,200 BPD.

72 Data for exports of ethanol from the United States is obtained from the USDA's Foreign Agricultural Service's Global Agricultural Trade System using the Harmonized (HS-10) product group information. http://www.fas.usda.gov/gats/default.aspx

**Figure 80: United States Ethanol Imports and Exports (1989 to January 2017)**




Sources: U.S. EIA, USDA Global Agricultural Trade System, and Energy Commission analysis.

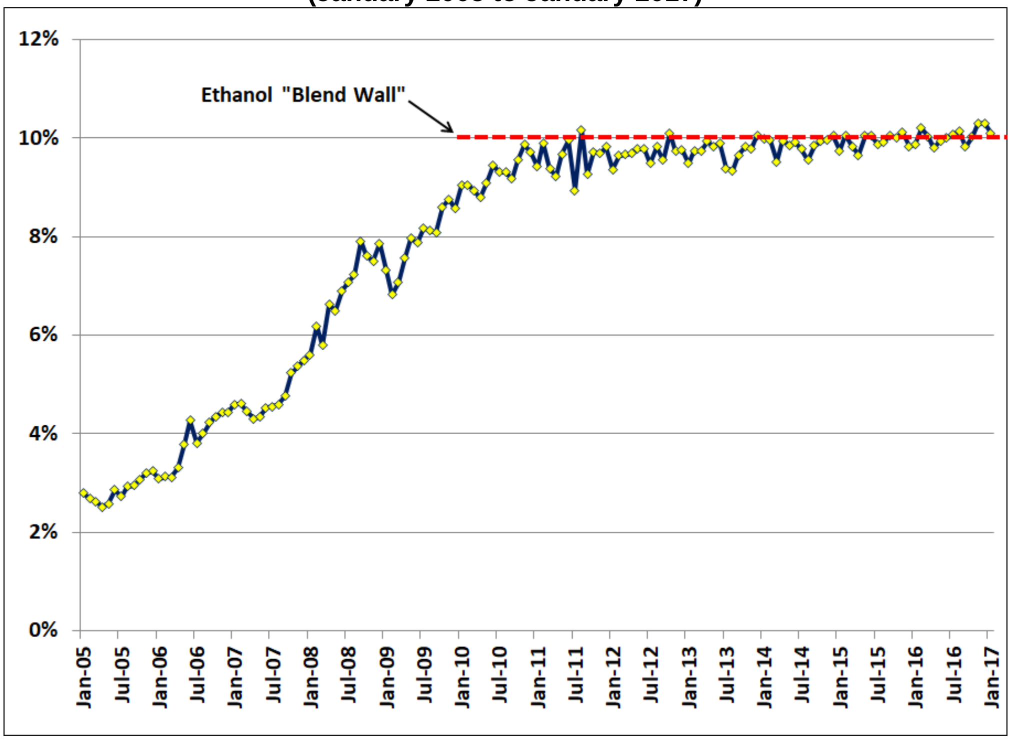
Increasing production of ethanol in response to federal biofuel use mandates over the last several years has resulted in a growing percentage of this renewable fuel displacing gasoline. When measured as a concentration in finished motor gasoline, ethanol use has grown steadily from approximately 3 percent by volume during 2005 to 10.1 percent by volume by January 2017, with a peak of 10.3 percent during December 2016 (see **Figure 81).** The average concentration of ethanol in finished gasoline appears to have increased steadily, plateauing at approximately 10 percent by volume beginning January 2014. Most states have regulations that cap the amount of ethanol in gasoline or the quantity of oxygen derived from the ethanol. This upper limit is referred to as the ethanol "blend wall". During the latter portion of 2016, ethanol concentration exceeded the blend wall during multiple months, a sign that sales of E15, E85 and other mid-range blends continue to grow as more of these types of fueling dispensers are installed throughout the country.[73] According to the *Growth Energy's Ethanol Retailer* website, there are 29 states that offer E15 at 809 retail locations.[74] The ability to dispense E15 is also limited due to the seasonal restriction that precludes sales during the vapor control period of the year (non-

73 E85 is a designation for a transportation fuel consisting of approximately 15 percent gasoline and 85 percent ethanol. This fuel cannot be used in standard light-duty gasoline-powered vehicles. Instead, E85 is a fuel compatible for use in flexible-fuel vehicles or FFVs. E15 is a transportation fuel that consists of 85 percent gasoline and 15 percent ethanol. This fuel can be used in light-duty gasoline-powered vehicles that are newer than 2001 model year. The majority of all vehicles manufactured today have a warranty that allows for ethanol concentrations of up to 15 percent by volume.

74 This information and other details associated with E15 may be viewed at the following link: http://www.ethanolretailer.com/e15-resource-center.

winter). There are currently no retail locations dispensing E15 in California, as that type of transportation fuel has yet to be approved for distribution in the state. E85 does not have a seasonal sales limitation and is sold at more than 3,200 locations nationwide, according the Department of Energy's Alternative Fuels Data Center.[75]. There were 136 locations listed as operational and dispensing E85 listed in California.

**Figure 81: United States Ethanol Concentration in Finished Gasoline (January 2005 to January 2017)**




Sources: Energy Commission analysis of U.S. EIA data.

The domestic ethanol industry has been under economic pressure over the last several years due to excess supply capacity and feedstock costs increasing at a greater pace than revenue streams from fuel ethanol and by-products such as distillers dry grains with solubles (DDGS). **Figure 82** tracks an aggregate measurement of ethanol plant gross margins by using data generated by an economic model developed by Ag Decision Maker (an agricultural economics and business website produced by Iowa State University) that is intended to capture all of the revenue and costs associated with a typical ethanol plant.[76]

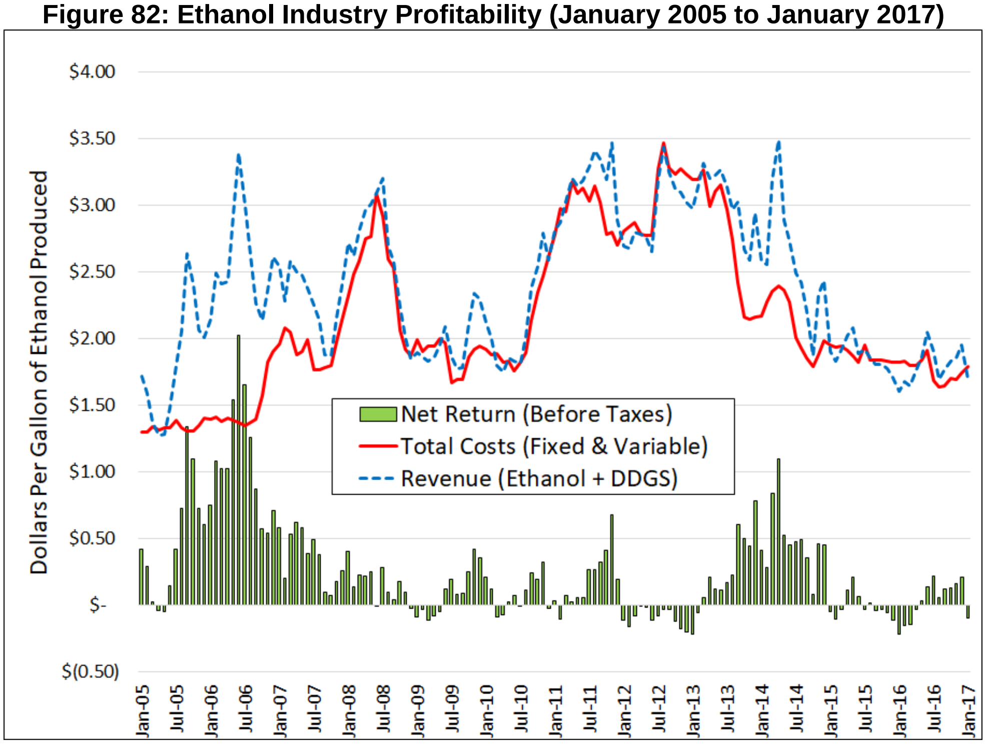
**Figure 82** illustrates that profitability of ethanol plants has declined significantly since 2006, primarily as the result of rising corn costs. Declining corn costs had greatly improved profitability by the summer of 2013 until excess supply and declining ethanol prices eroded profitability

75 As of June 2, 2017, there were 3,223 locations offering E85 for sale at both public and private locations. A list of individual locations may be accessed at the following link: https://www.afdc.energy.gov/data_download.

76 A link to the ethanol profitability plant model, assumptions and data is http://www.extension.iastate.edu/agdm/energy/xls/d1-10ethanolprofitability.xlsx. The data used to create the chart is contained in the tab marked "Returns per Gal."

during most of 2015 and the early portion of 2016. Most recently the net returns have turned positive, averaging 15 cents per gallon during the last half of 2016. Ethanol plants obtain revenue from the sale of fuel ethanol and, to a lesser extent, co-products of ethanol production. The primary co-product is distillers grains solubles (DGS) that can be dried to remove most of the water, so that the product can be transported and stored for long periods. Most of the DGS is sold as feed to the cattle industry.[77] The DGS produced by California ethanol facilities is not dried, referred to as wet DGS (WDGS) since feedlot customers are close to the ethanol plants, reducing the need for longer-term transportation and storage. WDGS production requires less energy (less natural gas for drying), yielding a lower carbon footprint when compared to ethanol dry mills in the Midwest. The importance of these ethanol plant co-products is highlighted in **Figure 83**, which illustrates that shares of DDGS revenue generally exceeded 20 percent of totals since the end of 2011. This development has allowed ethanol plants to remain profitable during periods of high corn prices and, recently, lower ethanol prices. During 2016, estimated DDGS revenue has averaged 20.4 percent of total estimated revenues for ethanol plants, down from the 23.9 percent for all of 2015.

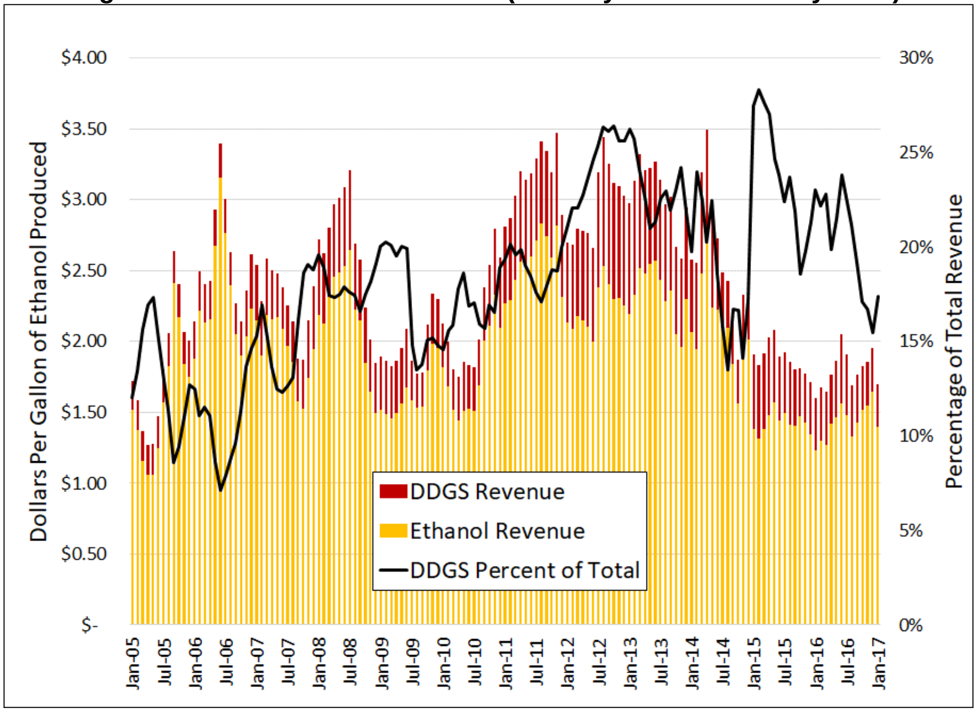
**Figure 82: Ethanol Industry Profitability (January 2005 to January 2017)**




Source: Data from Ag Decision Maker, Iowa State University.

77 A more detailed description of distillers grains with solubles (both dry and wet), their compositions and uses are contained in the following publication: *Corn Processing Co-Products Manual, A Review of Current Research on Distillers Grains and Corn Gluten*, Nebraska Corn Board and the University of Nebraska-Lincoln, 2005. http://beef.unl.edu/4ea342c5-839f-45c6-b166-667509fd8296.pdf

**Figure 83: Ethanol Plant Revenue (January 2005 to January 2017)**




Source: Data from Ag Decision Maker, Iowa State University.

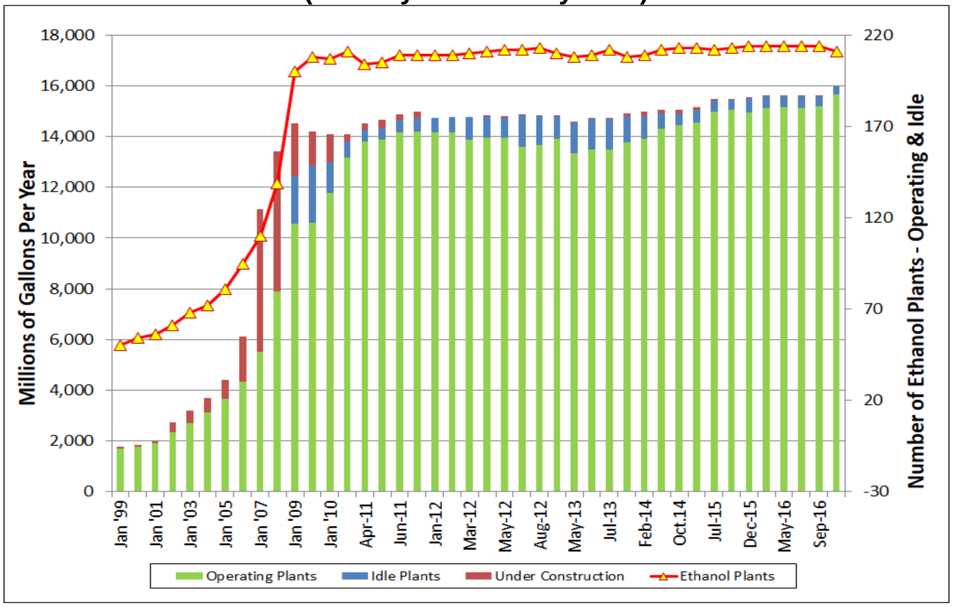
The ethanol market has experienced other periods of economic difficulties associated with changing cost structures, market price differentials between gasoline and ethanol, and evolving markets for various coproducts.[78] As of May 2017, there was an estimated 330 million gallons of idle ethanol production capacity in the United States, about 2 percent of total production capacity of 15.9 billion gallons.[79] **Figure 84** shows the annual ethanol plant capacity for the United States broken down by operating, idle, and under construction, along with the number of ethanol facilities. The overwhelming majority of these facilities use corn as their sole or primary feedstock. However, there are a growing number of facilities utilizing additional feedstocks (such as sorghum) that reduce their carbon intensity and have greater market interest under California's LCFS program. The pace of construction and expansion of additional ethanol plants that use corn for feedstock has slowed because the federal RFS2 regulations allow obligated parties to use a maximum of 15 billion gallons per year of that type of ethanol. Refiners and marketers can use even greater quantities of conventional ethanol, but that would not benefit them in their efforts to demonstrate compliance under that federal program.

---

78 A more detailed historical examination of ethanol markets is presented in Paul Gallagher's paper: *Roles for Evolving Markets, Policies, and Technology Improvements in U.S. Corn Ethanol Industry Development*, Federal Reserve Bank of St. Louis, Regional Economic Development, Volume 5, Number 1, 2009. http://research.stlouisfed.org/publications/red/2009/01/Gallagher.pdf

79 According to the Renewable Fuels Association (RFA), as of May 10, 2017, there was 16.1 billion gallons of ethanol nameplate production capacity in the United States. Energy Commission analysis of the plant list has resulted in removal of two facilities, leaving a nameplate capacity of 15.987 billion gallons. The two facilities not counted by the Energy Commission are the Columbia Pacific Bio-Refinery in Clatskanie, Oregon (108 million-gallon capacity), and the Golden Cheese Company of California facility in Corona, California (5 million-gallon capacity). Both of these facilities are considered "closed" rather than "idle." A link to the list is as follows: http://www.ethanolrfa.org/resources/biorefinery-locations/.

**Figure 84: United States Ethanol Plant Numbers and Capacities (January 1999 to May 2017)**




Source: Renewable Fuels Association and Energy Commission Analysis.

## Brazil Ethanol Supply

Ethanol from Brazil is produced from sugarcane, rather than corn. Since sugarcane cannot be stored once harvested, ethanol production in Brazil occurs seasonally, necessitating storage of sufficient ethanol to last until the following harvest cycle.[80] Brazil ethanol production is also tied closely with the production of sugar from cane juice. This means that ethanol plants in Brazil can adjust the ratio of ethanol-to-sugar in reaction to local ethanol demand/prices, export ethanol market economics, and world sugar demand/prices. In contrast, most United States ethanol producers do not have the flexibility to alter ethanol production by switching to another product. Ethanol production in the United States is adjusted by altering the quantity of corn processed. **Table 11** compares the differences in the ethanol industry between Brazil and the United States.

As is the case in the United States, Brazil ethanol production has continued to increase, after a temporary downturn, rebounding to reach a record output level of 7.9 billion gallons during 2015/16 harvest season (see **Figure 85**). Brazil produces two different types of ethanol: hydrous and anhydrous. Hydrous ethanol contains water in concentrations up to 7.5 percent, by mass.[81] This type of ethanol is used in flexible-fuel vehicles (FFVs) designed to operate on fuels containing ethanol between 27 percent and 100 percent, by volume (E100). Hydrous ethanol is also exported to other countries (especially in the Caribbean) that further process the ethanol to remove most of the water (dehydration step) before sending to the United States, duty free, under

80 Harvest of sugarcane in Brazil normally begins in April and is usually completed in November.

81 *Brazilian ANP Fuel Ethanol Specifications*, ANP, Resolution Number 19, April 15, 2015. A link to the document is as follows: http://www.itecref.com/pdf/Brazilian_ANP_Fuel_Ethanol.pdf.

the Caribbean Basin Initiative (CBI).[82] For all ethanol produced in Brazil, the initial steps of processing use water that must be removed to a level of less than 0.5 percent by volume if the ethanol is destined for low-level gasoline blends in Brazil or final export destinations. Once this dehydration step has been completed, the resulting product is referred to as anhydrous ethanol. This type of ethanol is suitable for blending with gasoline for use in low-level blends of up to 27 percent in Brazil and up to 10 percent by volume in the United States.[83]

**Table 11: Ethanol Operations in Brazil and United States (2015)**

| 2015 Comparison | Brazil | United States |
|---|---|---|
| Total Ethanol Plants | 382 | 214 |
| Total Ethanol Production (Billions of Gallons) | 7.3 | 14.8 |
| Average Plant Production (Millions of Gallons/Year) | 19.0 | 69.2 |
| Ethanol Production Per Acre of Feedstock (Gallons) | 588.0 | 477.3 |
| Ethanol Plant Operation | Seasonal | Year-round |
| Long-Term Feedstock Storage | No | Yes |

Source: Energy Commission Analysis.[84]

Production of ethanol in Brazil is determined by the interrelationship between various factors: minimum blending levels in gasoline as set by its Ministry of Agriculture; world sugar market demand, balances, and prices; outcome of sugarcane growing season; and the potential value of ethanol exports. Interactions of these market components determine whether there will be ample excess supplies of ethanol available to export from Brazil in any given year. Over the last five years (2012 through 2016), Brazil has exported between 368 million and 818 million gallons of ethanol (see **Figure 86**).[85]

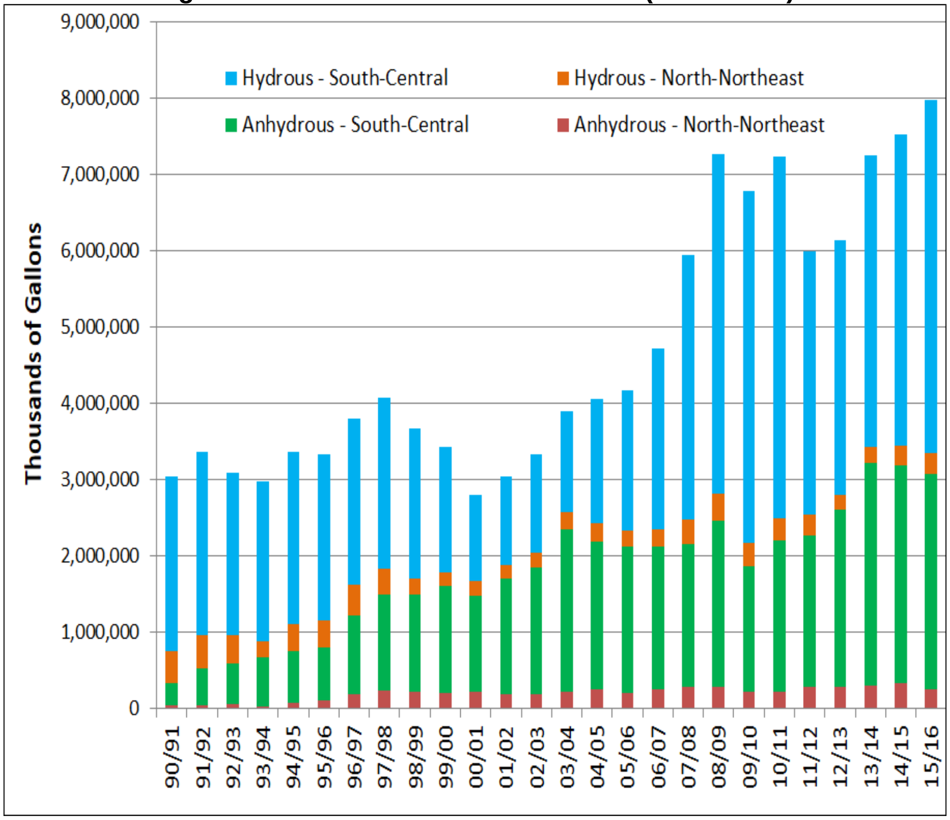
82 The Caribbean Basin Initiative is an economic development program designed, in part, to allow specific types of goods to be imported into the United States duty-free or at reduced tariff structures. A description of the program and eligible countries is contained in: "Guide to the Caribbean Basin Initiative," U.S. Department of Commerce, International Trade Commission, 2000 Edition. A link to the document is as follows: http://www.ita.doc.gov/media/Publications/pdf/cbi2000.pdf.

83 The Brazil Ministry of Agriculture sets the ratio of ethanol in low-level gasoline blends each year based on the market outlooks for both sugar and ethanol. The maximum blend limit is 27 percent by volume, as of March 16, 2015. *Brazil Biofuels Annual Report 2016*, Global Agricultural Information Network, Report number BR16009, August 12, 2016, page 3. A link to the document is as follows: https://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Sao%20Paulo%20ATO_Brazil_8-12-2016.pdf.

84 Brazil Biofuels Annual Report 2016, Global Agricultural Information Network, Report number BR16009, August 12, 2016. A link to the document is as follows: https://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Sao%20Paulo%20ATO_Brazil_8-12-2016.pdf.

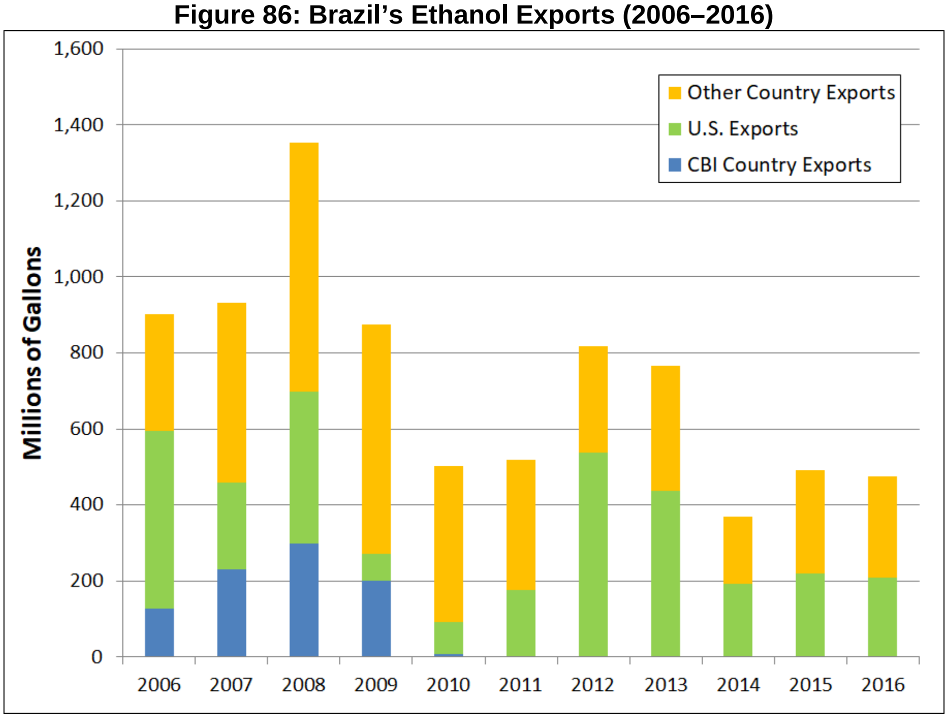
85 Country destination for Brazil's ethanol exports from the Boletim Mensal dos Conbustíveis Reonváveis n° 42 - junho de 2011, page 18. A link to this bulletin is as follows: http://www.mme.gov.br/portalmme/opencms/spg/galerias/arquivos/publicacoes/boletim_mensal_combustiveis_renovaveis/Boletim_DCR_nx_042_-_junho_de_2011.pdf.

**Figure 85: Brazil's Ethanol Production (1990–2016)**




Sources: UNICA, MAPA, USDA FAS, and Energy Commission analysis.

**Figure 86: Brazil's Ethanol Exports (2006–2016)**

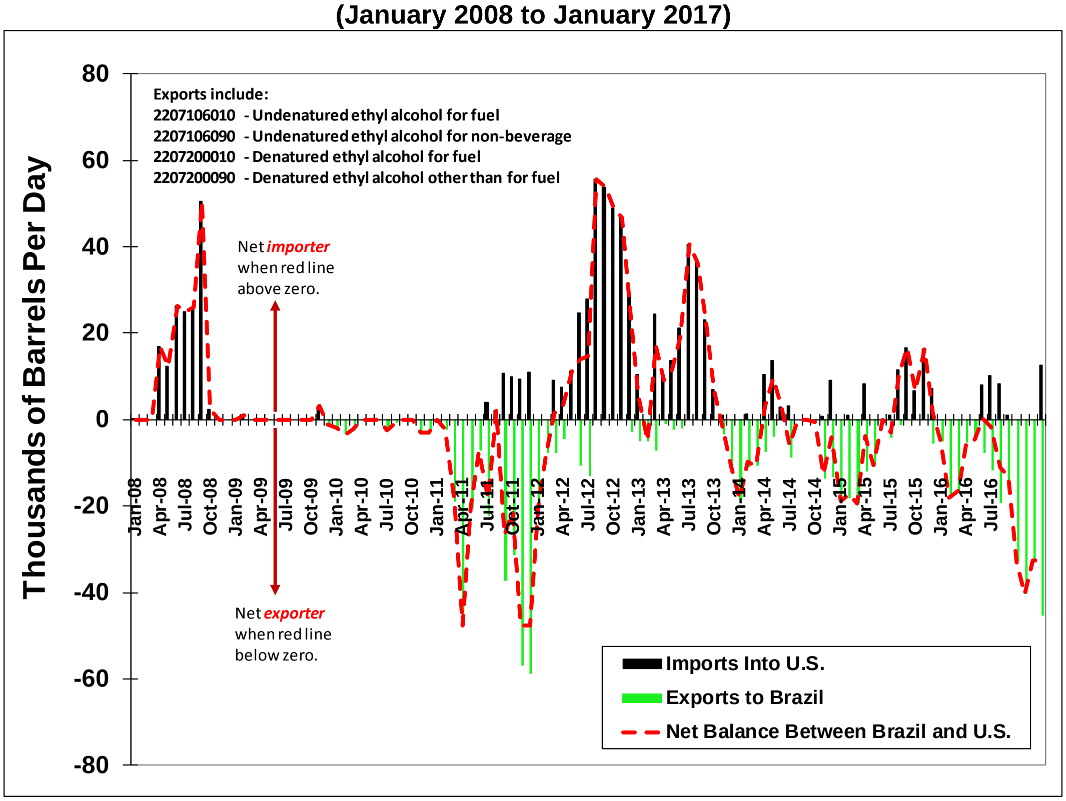



Sources: UNICA, Secex, and Energy Commission analysis.

Exports during 2016 totaled 474 million gallons, a decrease of 65 percent compared to the peak of 1.3 billion gallons during 2008. During that time, consumption has outpaced growth in production resulting in less ethanol available for export. The United States is normally the world's largest importer of Brazil ethanol, accounting for 44.3 percent of Brazil's exports for 2016. Over the next several years, demand for Brazilian exports to the United States is expected to remain strong and even grow as obligated parties under the federal RFS and LCFS in California and Oregon seek out ethanol supplies that have lower carbon intensities compared to domestic ethanol produced from corn and sorghum.

Although Brazil's ethanol exports to the United States have remained fairly stable since 2014, the quantity of ethanol being imported into Brazil from the United States has been steadily increasing. **Figure 87** depicts the exchange of ethanol flows between the two countries between January 2008 and January 2017. Since late 2013, the United States has become a growing net exporter of ethanol (more exports than imports). Production growth of ethanol in the United States has been increasing at a greater pace than demand growth, creating additional quantities of ethanol for export, the opposite of recent trends in Brazil. During 2012, the United States was a net importer of ethanol from Brazil, averaging 20,600 BPD (0.86 million gallons per day). By 2016, the circumstances had reversed, with the United States transitioning to a net exporter of ethanol to Brazil averaging 15.09 thousand BPD (0.63 million gallons per day).

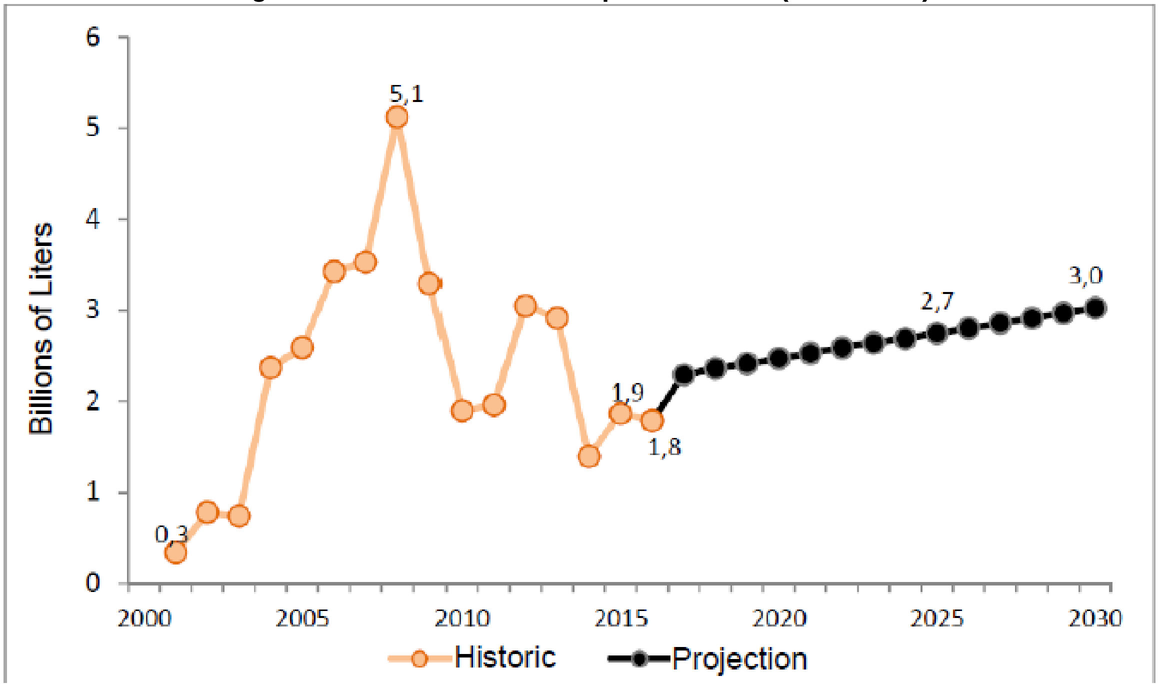
**Figure 87: Brazil's and United States Imports and Exports for Ethanol (January 2008 to January 2017)**




Sources: U.S. EIA, USDA Global Agricultural Trade System, and Energy Commission analysis.

The amount of excess ethanol that may be available to import from Brazil over the next several years (see **Figure 88**) is forecast to grow from 474 million gallons in 2016, to 713 million gallons (2.7 billion liters) by 2025, and 792 million gallons (3 billion liters) by 2030, a substantial reduction from the export forecasts from years earlier.

**Figure 88: Brazil's Ethanol Export Forecast (2017–2030)**




Source: Empresa de Pesquisa Energética.[86]

Based on the most recent ethanol export availability projections, Brazil's ability to supply significantly greater quantities of ethanol to the United States and California from excess production output over the next several years may be insufficient to meet the growing needs of federal and state renewable fuel programs. Even if one assumes that all of the incremental forecast export growth by 2025 (240 million gallons) were to be exported only to the United States, volumes from Brazil could amount to 450 million gallons, a figure less than the 510 million gallons exported to the United States during 2012. However, it should be possible for Brazil to examine the efficacy of developing a system of ethanol exchange whereby Brazil ships sugarcane-based ethanol to the United States and takes back Midwestern corn-based ethanol in the same marine vessel.[87] This contingency plan, referred to as the Sao Paulo-Houston shuffle, would help ensure adequate supplies of ethanol that meet the RFS2 advanced biofuel standards and the LCFS low-carbon requirements in California and Oregon.

---

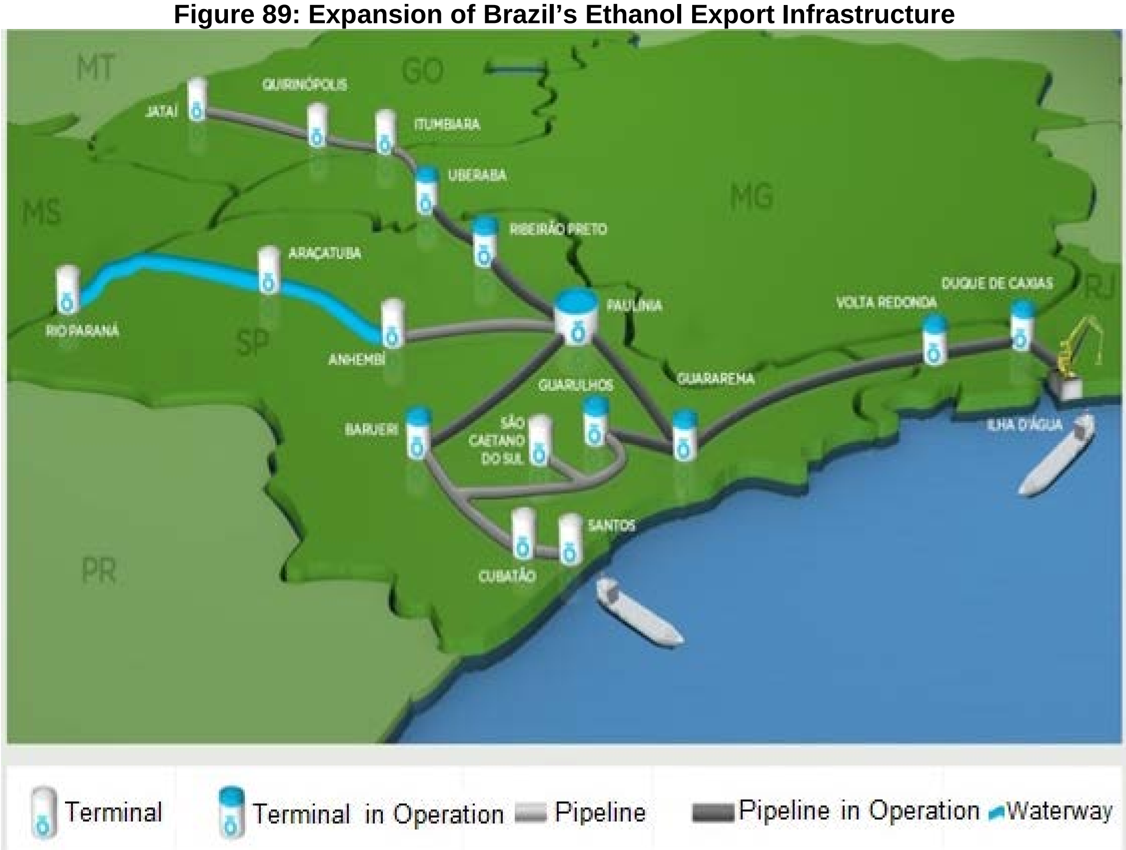
86 *Cenários de Oferta de Etanol e Demanda do Ciclo Otto: Versão Estendida 2030*, EPE, February 3, 2017, Chart 3, page 10. This document is in Portuguese. A link to the report is as follows: http://www.epe.gov.br/Petroleo/Documents/EPE-DPG-SGB-Bios-NT-02-2016-r1_Cen%C3%A1rios%20de%20Oferta%20de%20Etanol.pdf.

87 Marine vessels loaded with anhydrous ethanol from Brazil can discharge their cargo in Houston and then load their vessel with Midwest anhydrous ethanol for the voyage back to Brazil.

Brazil continues to develop an infrastructure that is designed to increase the quantity of ethanol that can be exported. In fact, Brazil is the only country that transports ethanol over significant distances via pipelines that are also used to ship petroleum products. **Figure 89** shows the existing and expanded infrastructure associated with an expansion of ethanol exports. During 2015, ethanol exports from the Port of Santos accounted for 90 percent of Brazil's total exports, followed by 7 percent from Paranaguá and 1 percent from Maceió.[88] Santos is located in south central Brazil, the primary sugarcane growing area and ethanol production center of the country.

The infrastructure for Brazil's ethanol imports utilizes other marine terminals located in the ports of São Luís (58.4 percent), Recife (11.2 percent), Santos (9.7 percent) and Manaus (7.6 percent).[89] São Luis is located in northern Brazil, furthest from production centers, Recife along central coastal Brazil, and Manaus located up the Amazon River (see **Figure 90**).

**Figure 89: Expansion of Brazil's Ethanol Export Infrastructure**




Source: Empresa de Pesquisa Energética.[90]

---

88 *Análise de Conjuntura dos Biocombustíveis, EPE*, May 10, 2016, page 30. This document is in Portuguese. A link to the report is as follows:http://www.epe.gov.br/Petroleo/Documents/An%C3%A1lise%20de%20Conjuntura%20dos%20Biocombust%C3%ADveis%2020boletins%20peri%C3%B3dicos/An%C3%A1lise%20de%20Conjuntura%20dos%20Biocombust%C3%ADveis 1%20-%20Ano%202015.pdf.

89 Ibid., page 31.

90 Ibid., page 31.

**Figure 90: Brazil's Ethanol Import Locations (2015)**


Source: http://www.ramonllull.net.

## California Ethanol Supply

Kinder Morgan's California pipeline system began accepting only base gasoline that will be used to blend E10 at all of their California distribution terminals on January 11, 2010.[91] The majority of gasoline distributed throughout California moves through some portion of the Kinder Morgan pipeline systems and refiners want to ensure that the type of gasoline they produce is compatible (to allow for volume exchanges and increased flexibility during unplanned refinery outages). That need, in conjunction with growing RFS2 renewable fuel requirements, is why California's gasoline market switched to E10 during the first quarter of 2010.

Currently, all four California corn-based ethanol facilities are operating, with a collective production capacity of nearly 215 million gallons per year.[92] Over the last couple of years there have been a number of projects completed at the California facilities to reduce energy consumption, lower carbon intensity of their ethanol output, and diversify feedstock utilization. Average carbon intensity of California producers during 2016 was 70.2 grams of carbon dioxide,

91 Kinder Morgan PowerPoint presentation, January 28, 2010, slide 16. A link to the presentation is as follows: http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/event/additional/2010_Analysts_Conf_06_Products_Pipes.pdf.

92 The following ethanol plants are currently operating in California: Aemetis in Keyes, Calgren Renewable Fuels in Pixley, Pacific Ethanol in Madera and Pacific Ethanol in Stockton.

which is equivalent per megajoule (gCO2E/MJ) compared to the average of 72.3 gCO2E/MJ for all other out-of-state ethanol producers that supplied the California market during 2016. Foreign imports of ethanol averaged a much lower 49.7 gCO2E/MJ due to use of sugarcane and molasses as feedstock.[93]

It is clear that the quantity of ethanol used in California transportation fuels will continue to increase as refiners and other marketers react to higher mandated ethanol levels that will be required by the RFS2. In addition, the California LCFS is expected to continue pushing obligated parties to select types of ethanol that have lower carbon intensities. At this time, ethanol produced from sugarcane in Brazil is the type of commercially available ethanol that has the lowest carbon intensity. As such, it is anticipated that California's logistical infrastructure for the importation and distribution of ethanol will need to continue to retain flexibility to import ethanol via marine vessels.

Most (85.9 percent) of the ethanol used in California was imported in rail tank cars from ethanol plants in the Midwest, accounting for 1.3 billion gallons during 2016. The majority of these imports are via unit trains of between 90 rail cars and 112 rail cars. This method of rail delivery is efficient in terms of transit time and costs as the unit trains usually receive priority use of the tracks and can transverse the distance from source to destination without stopping, except for crew changes or rest requirements. There are two facilities in Southern California that are capable of receiving unit trains of ethanol. The first facility is in Carson and is referred to as the Lomita Rail Off-Loading Terminal.[94] The operation of this terminal has an ethanol receipt capacity of up to 38,000 BPD or about 580 million gallons per year.[95] The second facility, referred to as the West Colton Rail Terminal, is operated by U.S. Development Group (USDG). This operation has an ethanol receipt capacity of up to 13,000 BPD or nearly 200 million gallons per year.[96] These two facilities could handle up to 100 percent of Southern California's rail receipts of ethanol. Northern California has rail receipt facilities located in Stockton, Richmond, and Selby where ethanol is transferred from rail tank cars to delivery tanker trucks in a process called transloading.[97]

Although California receives the majority of ethanol via rail cars from outside the state, only a few gasoline distribution facilities have the capability to handle rail cars full of ethanol. Instead, the overwhelming majority of California's distribution terminals that dispense gasoline receive all of the ethanol needed for blending via tanker truck deliveries that originate at the primary ethanol

---

93 Values based on analysis of pathway-specific renewable fuel use during 2016 by the California Energy Commission. Data provided by the California Air Resources Board.

94 A link to details associated with the Kinder Morgan Lomita rail off-loading facility is as follows: https://www.kindermorgan.com/content/docs/terminalbrochures/e-Lomita.pdf.

95 Kinder Morgan presentation, August 24, 2009, slide 7. A link to this presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-08-24_workshop/presentations/05_KMP_Tobin.pdf.

96 A link to the U.S. Development Group site for all terminals, including the West Colton facility, is as follows: http://usdg.com/terminal/west-colton/.

97 For a description of an ethanol transloading terminal operation (Norfolk Southern Ethanol Transloading Facility in Alexandria, Virginia), refer to the following presentation: *Ethanol Transloading*, City of Alexandria, Presentation to City Council, May 27, 2008. A link to this presentation is as follows: http://alexandriava.gov/special/transloading/docs/EthanolTransloadingPresentation052708.pdf.

rail receipt hub terminals. As California moved to E10 during 2010, the trucking industry and terminal operators responded to the increased throughput of ethanol at California's distribution terminals without any temporary logistical difficulties. Over the next several years ethanol demand will continue to grow, but at a more gradual pace than was experienced during the transition to E10. As such, the trucking logistics to handle future growth in ethanol demand are not expected to pose a challenge.

California can also receive ethanol via ocean-going marine vessels with the balance of ethanol supplies obtained from the output of California ethanol facilities. **Figure 91** breaks down the sources of ethanol for California since 2004.[98] During 2016, rail imports have accounted for 1.3 billion gallons (87.3 thousand BPD) or 87.4 percent of California ethanol supply, followed by 185.4 million gallons (12.1 thousand BPD) of in-state production (11.9 percent) and 34.1 million gallons (2.2 thousand BPD) of marine imports from foreign sources (2.2 percent).

Marine imports of ethanol to California are discharged at two docks in Northern California (Selby and Richmond) and a single dock in the Los Angeles Harbor. During 2016, 34.1 million gallons of imported ethanol were delivered to these locations with all of this volume sourced from Brazil. There is an aggregate spare capacity in these marine terminals as demonstrated by imports that were in excess of 140 million gallons during 2013.[99]

The last portion of the ethanol logistics distribution infrastructure involves the pipelines used to transfer transportation fuels from refineries to distribution terminals. Currently, no ethanol is shipped through any petroleum product pipelines that are also used to transport gasoline, diesel, or jet fuel. Kinder Morgan has demonstrated that ethanol can be successfully shipped in batches through their pipeline segment in Florida.[100] However, this practice is unlikely to be extended to California over the near to mid-term due to the advanced age and complexity of the California pipeline system, as well as a higher probability of water in the pipeline system due to changes in the pipeline elevation (hydraulic profile).[101] If, over a longer period, ethanol shipments do become an operational reality in California, the primary impact on ethanol logistical operations would be the reduction in truck trips from ethanol receipt hubs to all of the distribution terminals. However, the shipment of ethanol through California pipeline segments would also displace shipment capacity for other transportation fuels in those portions of the pipeline infrastructure at or near pumping capacity. In time, Kinder Morgan and other pipeline companies could make modifications to their pipeline distribution systems to increase pumping capacities if ethanol pipeline shipments were to occur in California.

---

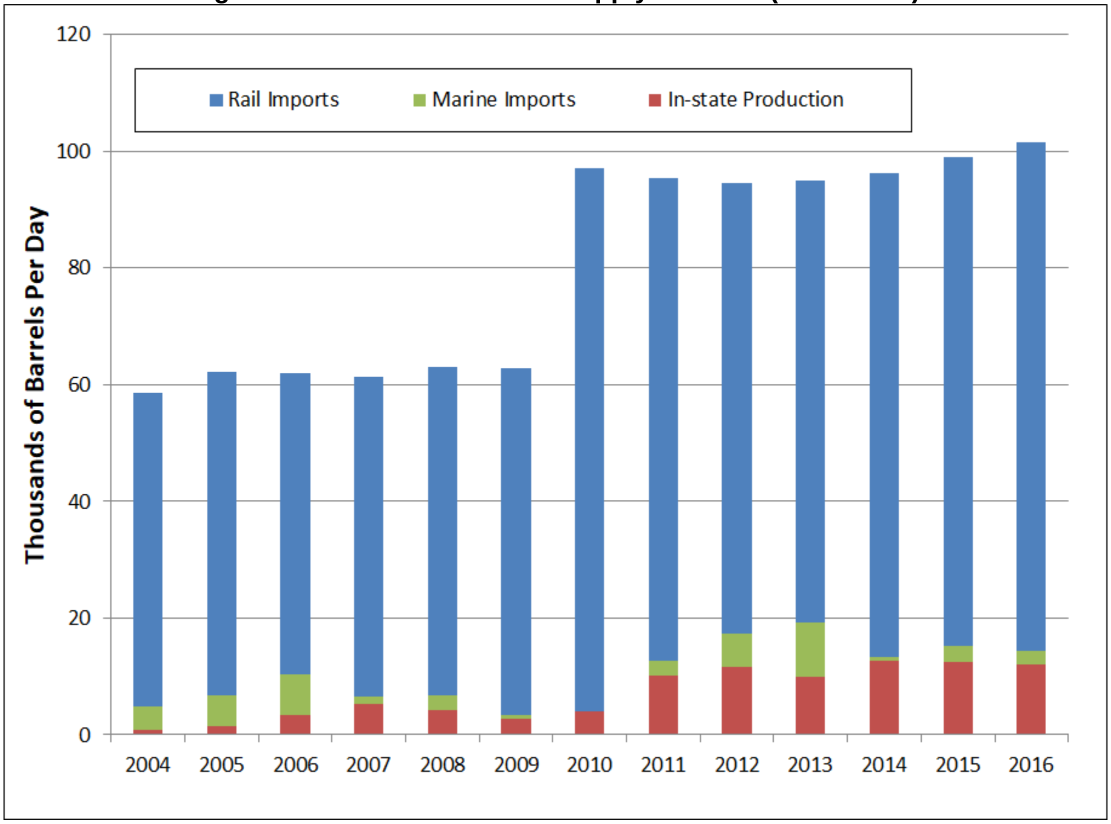
98 Rail imports are derived by subtracting California fuel ethanol production and marine imports from the estimated demand.

99 Energy Commission analysis of data provided by the California Air Resources Board.

100 "KMP Begins Commercial Operations of Ethanol Transportation on Central Florida Pipeline System," Kinder Morgan press release, December 2, 2008. A copy of the press release may be viewed at the following link: https://primis.phmsa.dot.gov/comm/publications/1202KMEthanol.pdf.

101 *Joint IEPR and Transportation Committee Workshop on Transportation Fuel Infrastructure Issues, transcript*, Ed Hahn comments, Kinder Morgan, April 14, 2009, pp. 201-4. A link to the transcript is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf.

Figure 91: California Ethanol Supply Sources (2004–2016)




Sources: U.S. EIA, CARB, and Energy Commission analysis.

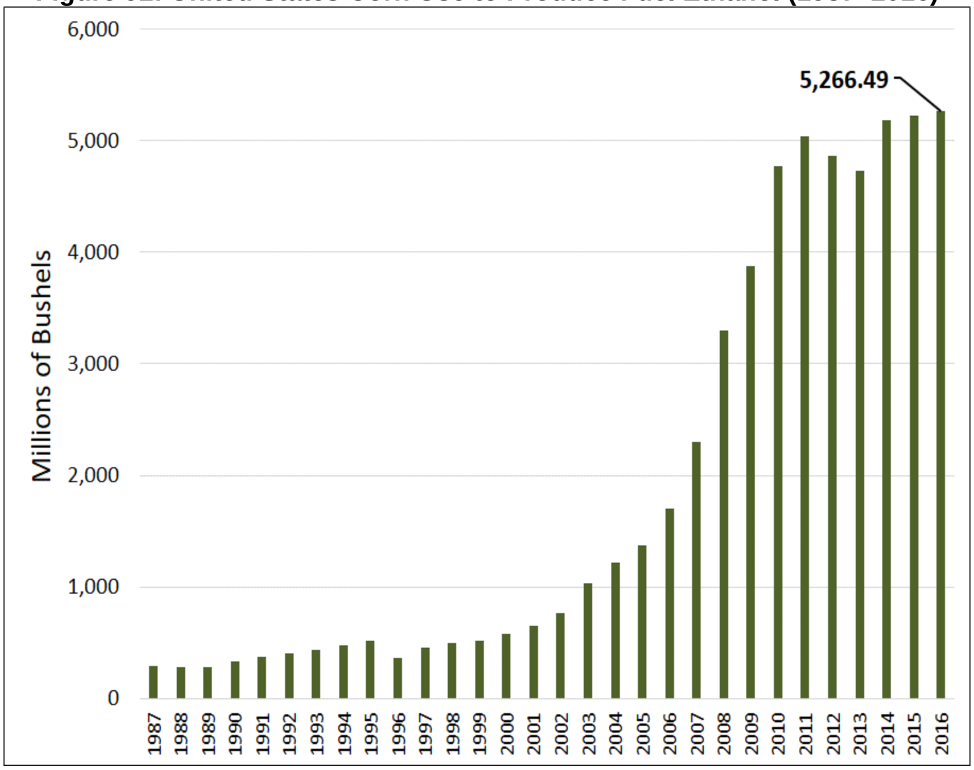
## Ethanol Feedstock Availability

The majority of fuel ethanol in the United States is produced in facilities that use corn as the primary feedstock. As the demand for ethanol continues to grow, so too does the demand for corn as a feedstock. **Figure 92** illustrates the quantity of corn that was used annually to produce ethanol since 1987. Corn used to produce ethanol accounted for a record 5.266 billion bushels during 2016.

During the earlier years of ethanol production and use, corn demand for producing ethanol was a small percentage of total use. However, **Figure 78** illustrates that the portion of corn required to produce ethanol has been increasing at an accelerated pace and accounted for approximately 37.4 percent of total use in 2016.[102] **Figure 93** shows the increasing use over the last 24 years.

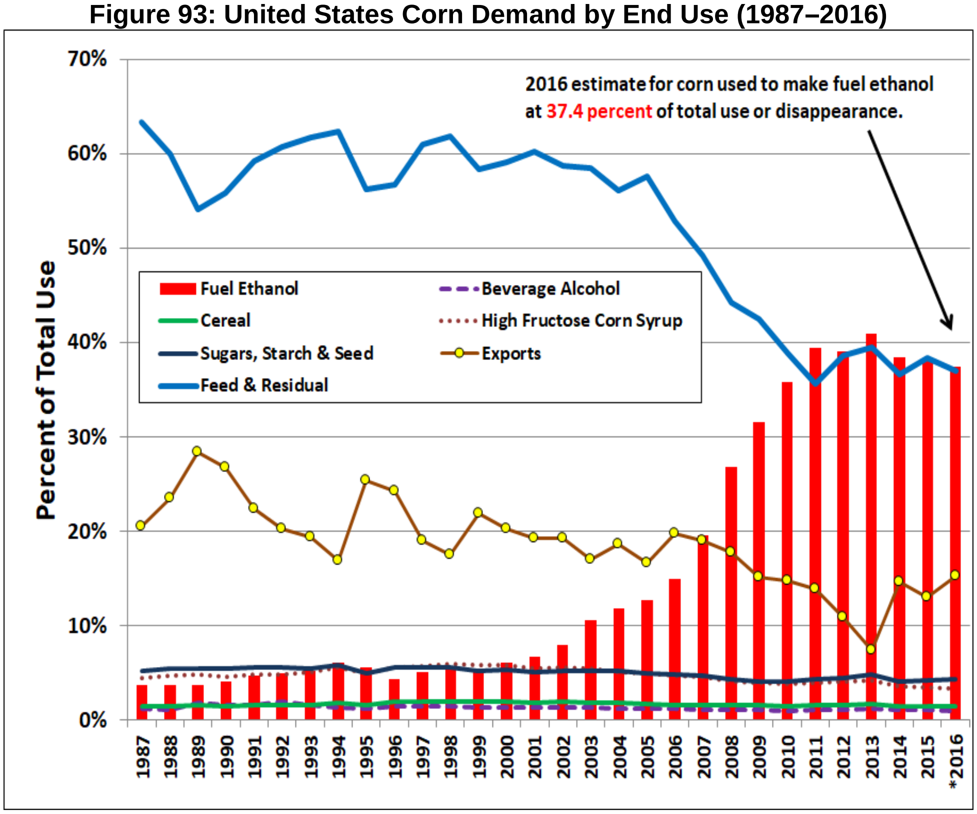
102 “Total Use” is referred to by USDA as “Total Disappearance” and is composed of “Domestic Use” and “Exports”. “Domestic Use” includes the following categories: Food, Alcohol, and Industrial use; Seed use; and Feed and Residual use. *Feed Grains Data: Yearbook Tables*, Corn: Food, Seed, and Industrial Use, Table 4, USDA, Economic Research Service. A link to the source is as follows: https://www.ers.usda.gov/data-products/feed-grains-database/feed-grains-yearbook-tables.aspx.

**Figure 92: United States Corn Use to Produce Fuel Ethanol (1987–2016)**




Source: USDA - National Agricultural Statistics Service.

**Figure 93: United States Corn Demand by End Use (1987–2016)**




Source: USDA - National Agricultural Statistics Service.

Corn is certainly the dominant feedstock used to create fuel ethanol in the United States, but not the only one. Sorghum grain is also used to produce fuel ethanol, albeit in much smaller portions, and is estimated to have accounted for roughly 120 million bushels during 2016.[103] This means that sorghum contributed to about 340 million gallons (2.2 percent) of all ethanol production during 2016. Although modest, the portion of domestically produced ethanol used in California during 2016 that was created from sorghum was nearly 130 million gallons or 8.2 percent.[104]

# Biodiesel Supply Outlook

Biodiesel is a general term used to describe mixtures of diesel fuel with varying concentrations (between 2 and 20 percent) of biomass-based distillate. Early use of biomass-based distillate dates back to at least 1900, when Rudolph Diesel used peanut oil in a diesel engine at the World's Fair in Paris.[105] The earliest reference to biodiesel (ethyl esters of palm oil) is from a 1937 Belgium patent, followed by application in a commercial urban bus route between Brussels and Leuven, Belgium, during the summer of 1938.[106] Biodiesel use continued up through World War II as a necessity brought about by shortage and security. Increased availability of relatively inexpensive petroleum-based diesel fuel essentially eliminated biodiesel use until a resurgence spurred by the 1990 Clean Air Act Amendments and the Energy Policy Act of 1992.[107] More recently, sales of biodiesel in California continue to increase due to the LCFS.

Blenders of biodiesel are permitted to vary the concentration in diesel fuel depending on which standard is adhered to for the final blend. Low-level biodiesel blends can range from 2 percent to 5 percent of B100 mixed with the conventional diesel fuel to meet American Society for Testing and Materials (ASTM) international specification D975. Higher blends of B100 between the range of 6 percent and 20 percent by volume must meet ASTM international specification D7467-15c ε 1.[108] A survey of biodiesel producers in the United States was conducted in 2004 to identify the properties of both B100 and B20.[109] A survey was carried out in March and April 2007 to test the quality of biodiesel blends being sold at retail.[110] A subsequent study of B20

103 Estimate according to the United Sorghum Checkoff Program. A link to the source is as follows: http://www.sorghumcheckoff.com/market-opportunities/renewables.

104 Energy Commission analysis of data provided by the California Air Resources Board.

105 *Historical Perspectives On Vegetable Oil-Based Diesel Fuels*, Gerhard Knothe, Updated December 23, 2009, pp. 1-2. A link to this re-published article by the American Oil Chemists' Society is as follows: http://aocs.files.cms-plus.com/LipidsLibrary/images/Importedfiles/lipidlibrary/history/Diesel/file.pdf.

106 Ibid., page 5.

107 Ibid, page 3.

108 National Renewable Energy Laboratory, *Biodiesel Handling and Use Guide,* fifth edition, publication number DOE/GO-102016-4875, revised November 2016, page 20. A link to the revised document is as follows: http://biodiesel.org/docs/using-hotline/nrel-handling-and-use.pdf?sfvrsn=4.

109 National Renewable Energy Laboratory, *Survey of the Quality and Stability of Biodiesel and Biodiesel Blends in the United States in 2004*, publication number NREL/TP-540-38836, October 2005, pages 18, 49, and 50. A link to the survey is as follows: http://biodiesel.org/reports/20051001_gen356.pdf.

110 *Quality Survey of Biodiesel Blends Sold at Retail Stations*, Haiying Tang, et al, Elsevier, available online June 2, 2008. A link to the research paper is as follows: http://www.eng.wayne.edu/user_files/414/file/Quick_Upload/Quality%20survey%20of%20biodiesel%20blends%20sold%20at%20retail%20stations%282%29.pdf.

obtained from retail stations and fleet operators was carried out during the summer of 2008.[111] The overwhelming majority of the samples complied with all or most ASTM standards prevailing at the time of the respective surveys. However, there was a consistent finding of biodiesel concentration variability in low-level blends.

Production of biodiesel in the United States increased dramatically (see **Figure 94**) in response to the RFS2 requirements and federal legislation that went into effect in 2005, which included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel. This legislative push has resulted in a record 1.5 billion gallons of biodiesel being produced by 2016. But output declined in 2009 and 2010 with the temporary loss of that tax subsidy in conjunction with poor production economics (high feedstock costs relative to market price of diesel fuel).[112] The blending credit has been allowed to expire at the end of 2009, 2011, 2013, 2014, 2015, and 2016.[113] In each of these instances the biodiesel tax credit was eventually re-instated and applied retroactively. The blending credit for 2017 has yet to be renewed. Further, initial proposals by Congress suggest that the blending credit be modified to become a production credit and have the change be in effect through 2020.[114]

---

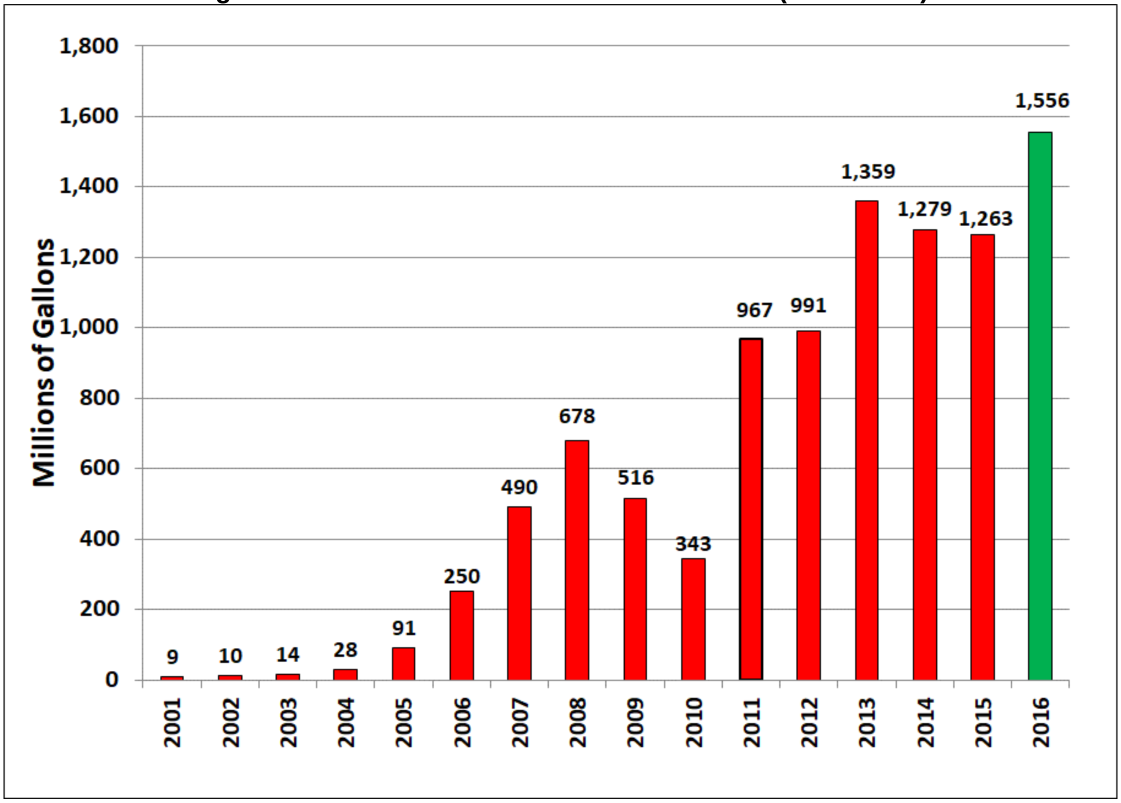
111 National Renewable Energy Laboratory, *Analysis of Biodiesel Blend Samples Collected in the United States in 2008*, publication number NREL/TP-540-46592, Revised December 2010. A link to the survey is as follows: http://www.nrel.gov/docs/fy11osti/46592.pdf.

112 The $1-per-gallon volumetric biodiesel blending credit originated in the JOBS Act of 2004 legislation. This portion of the act was intended to encourage increased biodiesel production, higher blending into diesel fuel, and the creation of additional agricultural jobs. A link to this information is as follows: http://transportpolicy.net/index.php?title=US:_Fuels:_Biofuel_tax_credits.

113 *Why Do Blenders Share Retroactively Reinstated Tax Credits with Biodiesel Producers?*, FarmDocDaily, Scott Irvin, July 22, 2015. A link to this article is as follows: http://farmdocdaily.illinois.edu/2015/07/why-blenders-share-retroactively-reinstated-tax.html.

114 Tax Incentive Action Page, Biodiesel.Org. A link is as follows: http://biodiesel.org/policy/fueling-action-center/tax-incentive-action-page.

**Figure 94: United States Biodiesel Production (2001–2016)**




Source: U.S EIA.

## United States

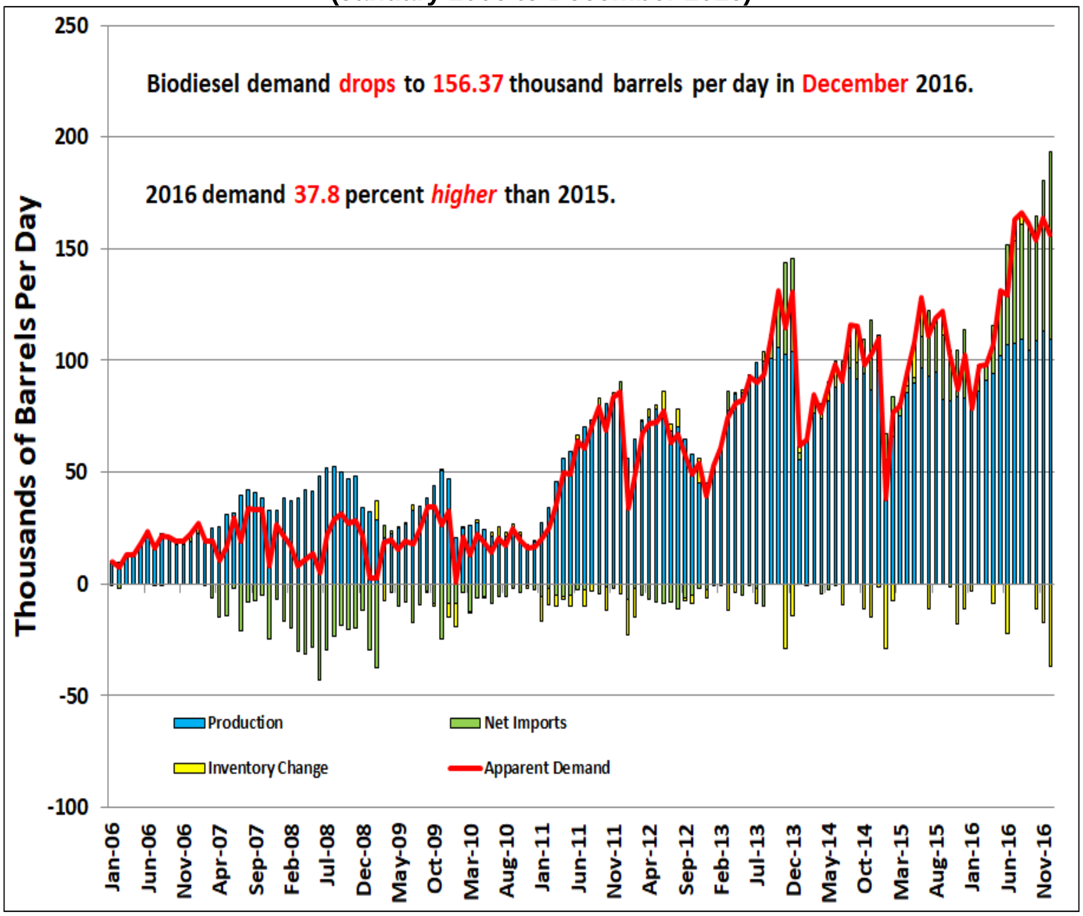
Demand for biodiesel as a transportation fuel has been erratic, primarily a consequence of changing subsidy policies and expensive feedstock costs. **Figure** 95 shows supply and demand for United States biodiesel between January 2006 and December 2016. Biodiesel consumption set a record in April 2016 of 166.3 thousand BPD.[115] The demand for biodiesel is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal RFS2. The federal requirement has increased from 1.63 billion gallons in 2014 to 2.0 billion gallons for this year (2017) and a further increase to 2.1 billion gallons scheduled for 2018.[116]

---

115 Apparent demand for biodiesel is calculated by summing production and imports, subtracting exports and adjusting for changes in inventory levels. The U.S. EIA is the source for the data. A link to the monthly biodiesel data is as follows: http://www.eia.gov/totalenergy/data/monthly/.

116 Final Renewable Fuel Standards for 2017, and the Biomass-Based Diesel Volume for 2018, U.S. Environmental Protection Agency. A link to the rule summary is as follows: https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuel-standards-2017-and-biomass-based-diesel-volume.

**Figure 95: United States Biodiesel Supply and Demand (January 2006 to December 2016)**




Sources: U.S EIA and Energy Commission analysis.

As of February 2017, there was nearly 2.3 billion gallons of biodiesel production capacity for all United States operating facilities.[117] There should be sufficient domestic biodiesel production capacity to meet the RFS2 requirements for 2017 (2 billion gallons) and 2018 (2.1 billion gallons), assuming high utilization rates are maintained. However, imports of biodiesel have been increasing and are another potential source of incremental supply to help meet higher use obligations if a portion of these imports prove to be a more economical means of compliance for obligated parties.

Significant quantities of biodiesel were exported between 2007 and 2009 due to more attractive wholesale prices and United States exporters' use of the dollar-per-gallon biodiesel blending credit (see **Figure 96**.) Biodiesel exports grew from nearly 9 million gallons in 2004 to a peak of 700 million gallons in 2008.[118] After peaking in 2008, a declining percentage of total United States biodiesel supply has been exported, leveling off to nearly 90 million gallons for each of the

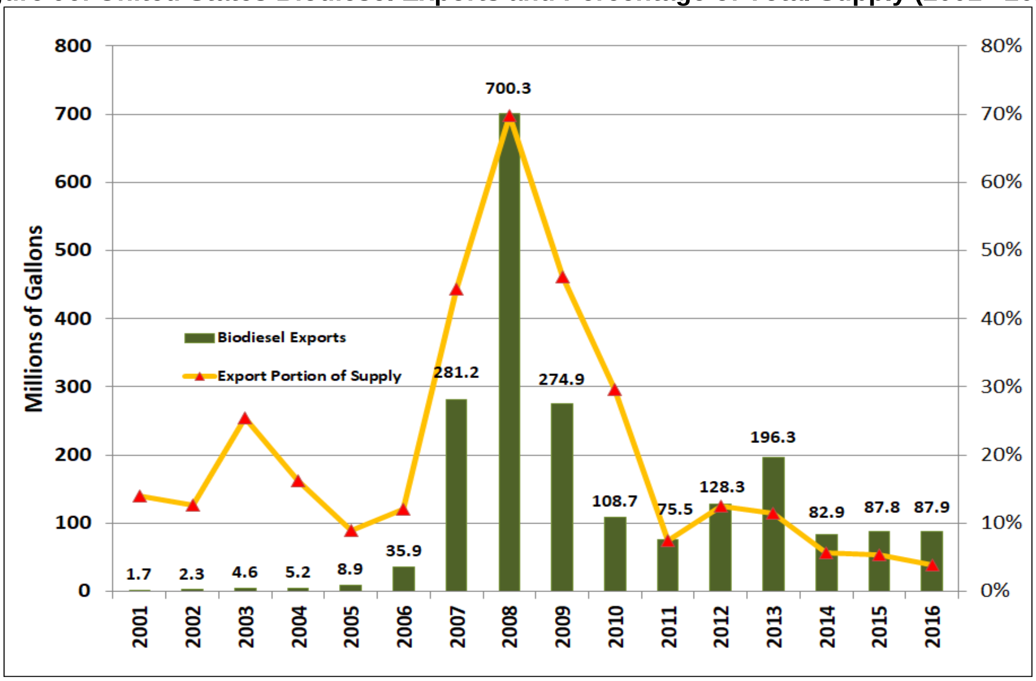
---

117 *Monthly Biodiesel Production Report*, U.S. EIA, April 2017, Table 4, page 8. There were 95 operating biodiesel facilities with an aggregate annual production capacity of 2.272 billion gallons. A link to this information is as follows: https://www.eia.gov/biofuels/biodiesel/production/biodiesel.pdf.

118 U.S. EIA, Monthly Energy Review. A link to the information under the Renewable Energy section is as follows: http://www.eia.gov/totalenergy/data/monthly/#renewable.

last three years. Exports as measured against total biodiesel supply have also continued to decline, reaching a record low of 3.9 percent during 2016. Ever higher levels of biomass-based diesel obligation under the RFS2 has minimized exports, driven domestic production higher, and encouraged record imports that amounted to 605 million gallons during 2016.

**Figure 96: United States Biodiesel Exports and Percentage of Total Supply (2001– 2016)**

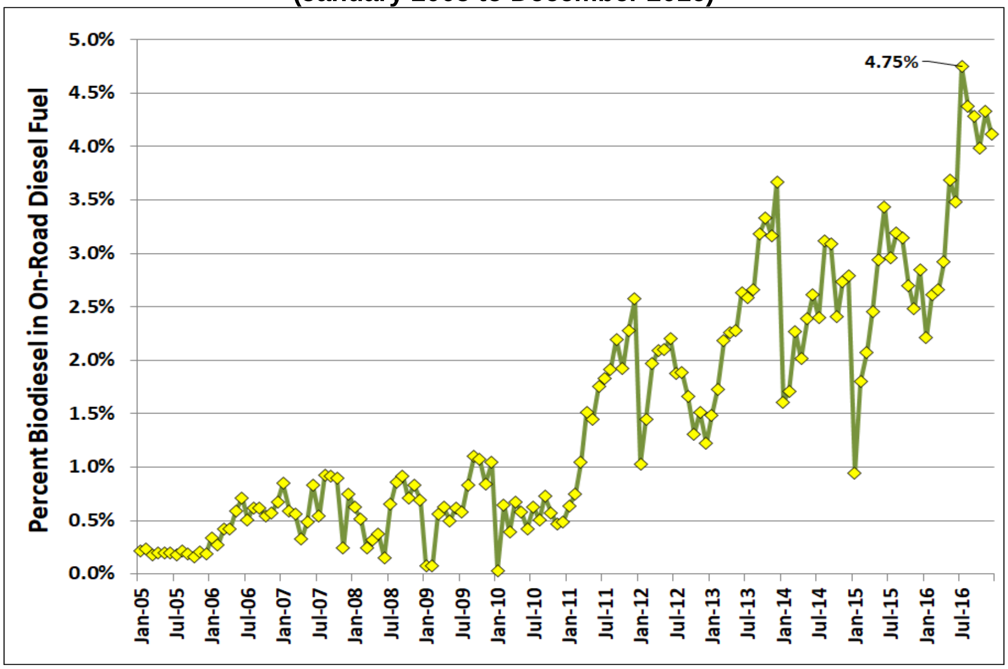



Source: U.S EIA.

Since June 2014, the United States has shifted to a net importer of biodiesel (imports exceed exports). Reduced exportation of domestic biodiesel production from the United States to Europe resulted in biodiesel blending levels that have fluctuated between 0.2 percent and 1.2 percent, as illustrated by **Figure 97**. Only since the beginning of 2011 have use levels started to climb due to the reinstatement of the blending credit and the need to meet RFS2 biomass-based diesel minimum-use levels. In fact, the average concentration of biodiesel in United States diesel during July 2016 reached 4.75 percent, an all-time record. Over the next couple of years, production and use of biodiesel are expected to continue to grow due to even higher levels, as mandated by the RFS2 regulations that compel 2 billion gallons of use during 2017 and 2.1 billion gallons for 2018.

The oscillating pattern of monthly concentration shows levels reaching a low point during the winter months before rebounding. This phenomenon has likely been due to the expiration of the blending tax credit that temporarily decreased the profitability of biodiesel sales and caused facilities to either reduce output or temporarily shutter operations. It is less likely that blending concerns for cold-weather locations could be a factor since concentrations during December show some of the higher levels of biodiesel use for several of the years. Colder temperatures can lead to the formation of waxy crystals in the fuel mixture that increase the likelihood of fuel filter plugging. The type of oils used to create the biodiesel also cause variability in pour point properties. However, concentrations of biodiesel at 5 percent by volume and below seem relatively unaffected by cold temperatures as long as the petroleum diesel fuel portion is properly treated. Higher concentrations of biodiesel require additional handling procedures to reduce the risk of filter clogs.[119]

**Figure 97: United States Biodiesel Blending Levels (January 2005 to December 2016)**



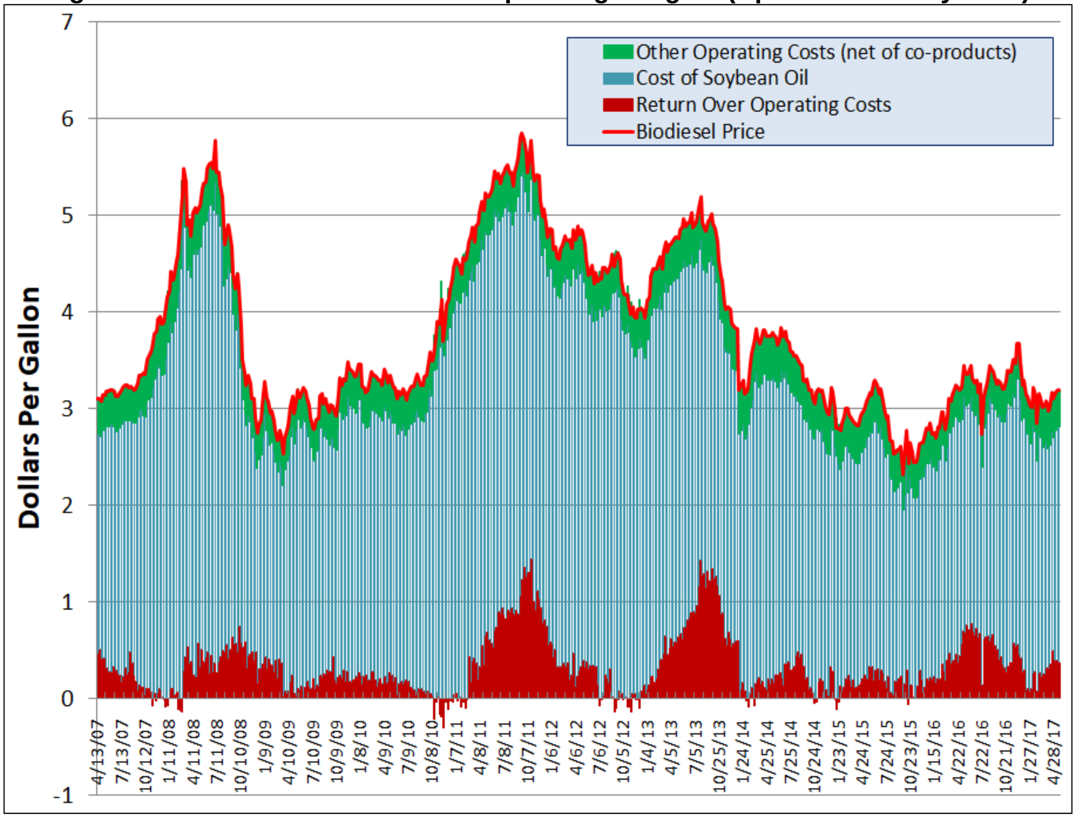

Sources: U.S. EIA and Energy Commission analysis.

The domestic biodiesel industry has periodically been under economic pressure due to excess supply capacity; temporary loss of a $1 per gallon blending credit; and expensive feedstock costs. **Figure 98** tracks an aggregate measure of a biodiesel plant operating return from data collected and analyzed by the Center for Agriculture and Rural Development that is intended to capture all of the revenue and costs associated with a typical biodiesel plant using soybean oil as a feedstock.[120] This chart is intended to convey degrees in fluctuation of biodiesel production profitability and not represent all biodiesel production operations that can vary significantly in operating costs and the type of feedstock utilized.

119 *Biodiesel Cold Flow Basics*, National Biodiesel Board, 2014. A link to the PowerPoint presentation is as follows: http://biodiesel.org/docs/default-source/ffs-performace_usage/cold-flow-basics---ppt.ppt?sfvrsn=6.

120 A link to the biodiesel profitability tracking assumptions and data is as follows: http://www.card.iastate.edu/research/biorenewables/tools/hist_bio_gm.aspx.

**Figure 98: United States Biodiesel Operating Margins (April 2007 to May 2017)**




Source: Center for Agricultural and Rural Development, University of Iowa.

## California Biodiesel Supply Outlook

According to the U.S. EIA, there are seven operating biodiesel production facilities in California as of February 2017, with an annual production capacity of 76 million gallons.[121] These production capacity volumes are not sufficient to supply all of California's total RFS2 "proportional-share" of biodiesel that is estimated to be about 130 million gallons for 2017.[122] Compliance with RFS2 requirements by obligated parties are national, rather than state specific. This means that refiners and importers can elect to market biodiesel in greater proportions in selected subregions of the United States. Further, the RFS2 requirements do not specify the type of feedstock that needs to be used to create the biodiesel. As such, soybean oil is the predominant feedstock of choice.

**Figure 99** shows how the feedstocks used to create biodiesel have changed since 2009.[123] As shown, biodiesel feedstock use has increased from 3,624 million pounds in 2009 to 11,123 million pounds in 2016, a 307 percent increase. This dramatic rise is in direct response to the RFS2 biomass-based diesel requirement increasing from 1.15 billion gallons in 2010 to 1.90 billion

---

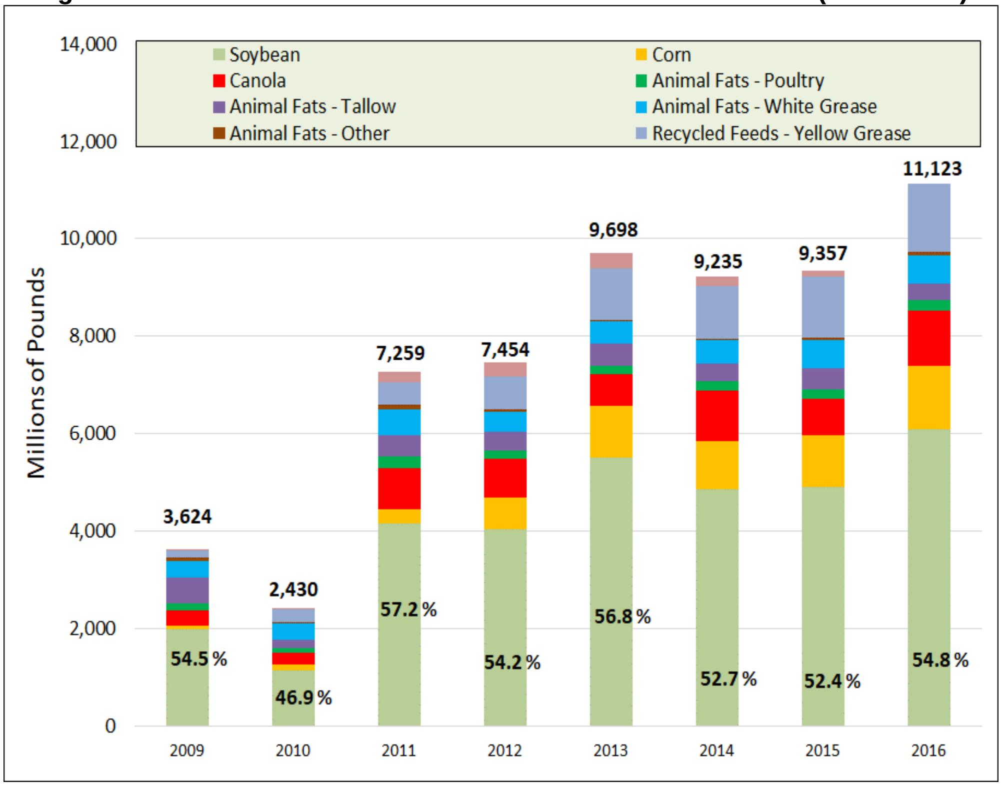
121 Ibid., page 8.

122 California's proportional share of the RFS2 biomass-based diesel obligation is calculated by dividing California's diesel fuel consumption from 2016 (3.697 billion gallons) by the United States' ultra-low sulfur diesel fuel consumption for 2016 (56.809 billion gallons) to yield 6.51 percent. The 2017 RFS2 obligation of 2.0 billion gallons multiplied by 6.51 percent yields 130 million gallons of biomass-based diesel.

123 *Monthly Biodiesel Production Reports*, U.S. EIA. A link to this information is as follows: https://www.eia.gov/biofuels/biodiesel/production/.

gallons for 2016.[124] Soybean oil totals have remained fairly stable during this period, fluctuating between 46.9 and 56.8 percent of total feedstock share.

**Figure 99: United States Feedstocks for Biodiesel Production (2009–2016)**

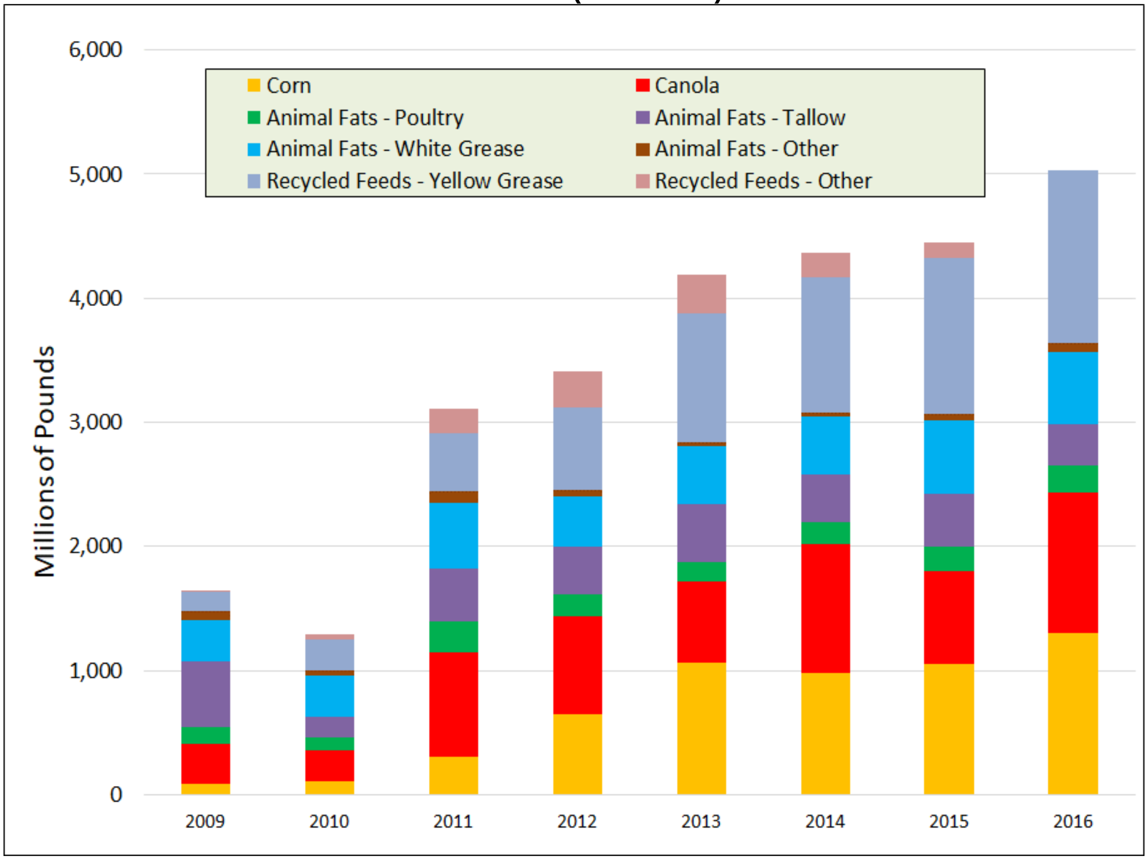



Source: U.S. EIA.

Removal of the soybean oil data from the chart allows for a closer examination of the remaining oils, fats, and recycled greases as illustrated in **Figure 100**. Even though fats and recycled greases have doubled from 1,239 million pounds in 2009 to 2,591 million pounds in 2016, their share of total feedstocks has declined from 34.2 percent in 2009 to only 23.3 percent in 2016. The large increase was overwhelmed by the huge jump in soybean oil use as a feedstock.

124 Information related to the final biomass-based diesel requirements for years 2010 through 2013 refer to the following link: https://www.epa.gov/renewable-fuel-standard-program/renewable-fuel-annual-standards.
Information related to the final biomass-based diesel requirements for years 2014 through 2018 refer to the following link: https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuel-standards-2014-2015-and-2016-and-biomass-based.

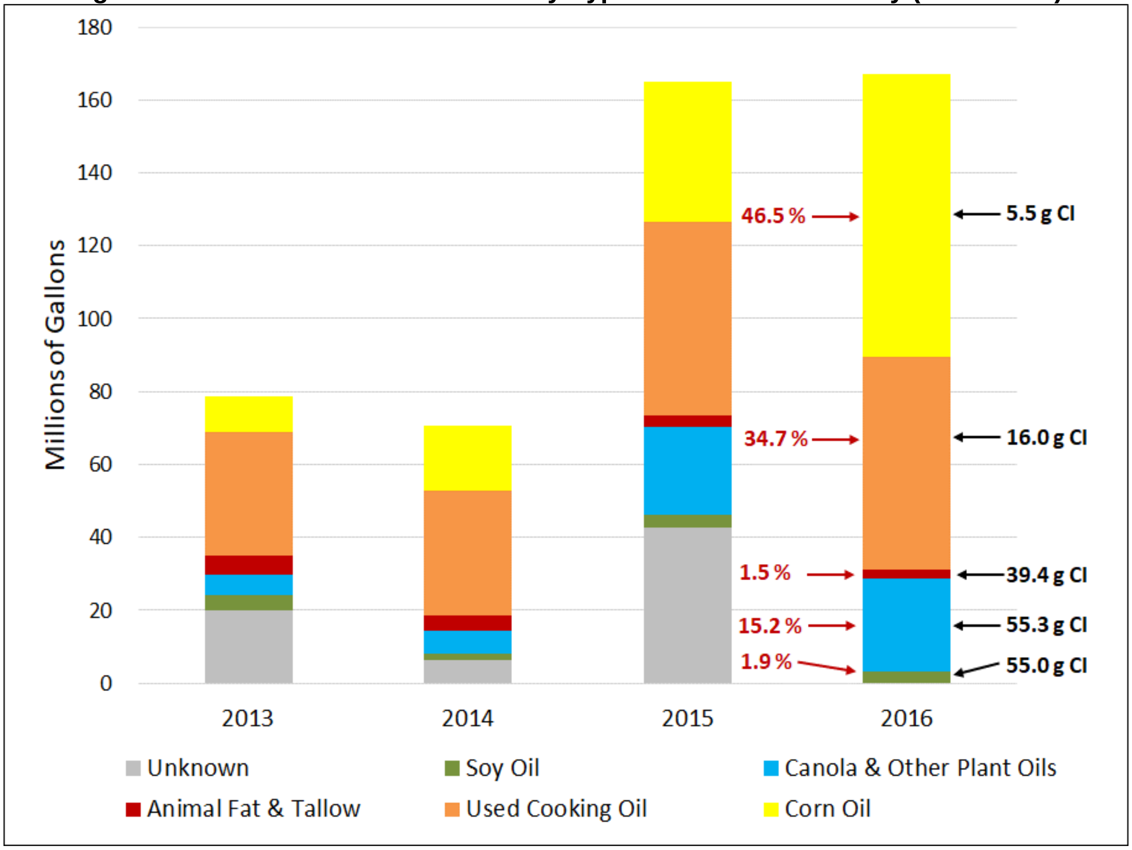
**Figure 100: United States Feedstocks (Excluding Soybean Oil) Used in Biodiesel Production (2009–2016)**




Source: U.S. EIA.

However, California's LCFS requirement is driving a growing use of fuels with lower carbon intensity. Biodiesel produced from soybean oil has a higher carbon intensity compared to other types of feedstock. As a result, LCFS-obligated parties and California producers have gravitated toward non-soybean feedstocks. **Figure 101** shows the diversity and trends for biodiesel feedstocks between 2013 and 2016. During 2016, soybean oil feedstock was used in nearly 55 percent of all biodiesel production in the United States, but was the source of only 1.9 percent of all the biodiesel consumed in California. Corn oil-feedstock was used in 11.7 percent of biodiesel production in the United States during 2016. However, corn oil-based biodiesel made up 46.5 percent of California's consumption due to its low carbon intensity score of 5.5 gCO2e/MJ.

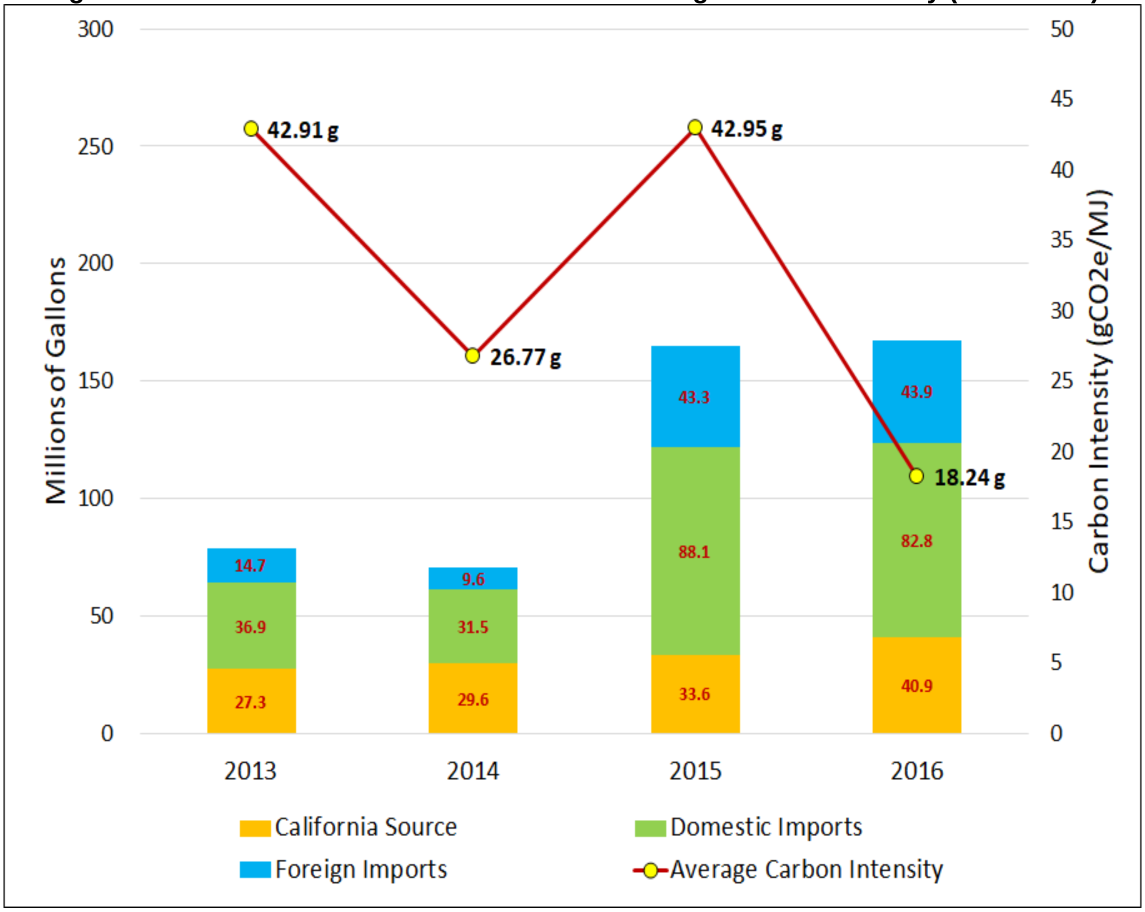
Figure 101: California Biodiesel Use by Type and Carbon Intensity (2013–2016)




Source: Analysis of CARB LCFS data by Energy Commission.

The percentage values (in red) above are based on the 167.2 million gallons of use during 2016. The carbon intensity values (in black) are indicated for each biodiesel type for that year. As mentioned earlier in this chapter, California's biodiesel production capacity of 76 million gallons per year is insufficient to solely meet the combined demand for RFS2 and the LCFS, necessitating imports of biodiesel from both domestic and foreign sources, **Figure 102** shows the annual contribution by source and average carbon intensity by all sources combined between 2013 and 2016. Carbon intensity has continued to decline, reaching 18.24 gCO2e/MJ in 2016, as use of lower CI biodiesel increases and higher CI biodiesel sources decrease. California-produced biodiesel accounted for 40.9 million gallons during 2016 (24.4 percent of total supply) with foreign imports of 43.9 million gallons (26.2 percent) and domestic imports of 82.8 million gallons (48.4 percent) accounting for nearly half of total biodiesel supply.

**Figure 102: California Biodiesel Sources and Average Carbon Intensity (2013–2016)**

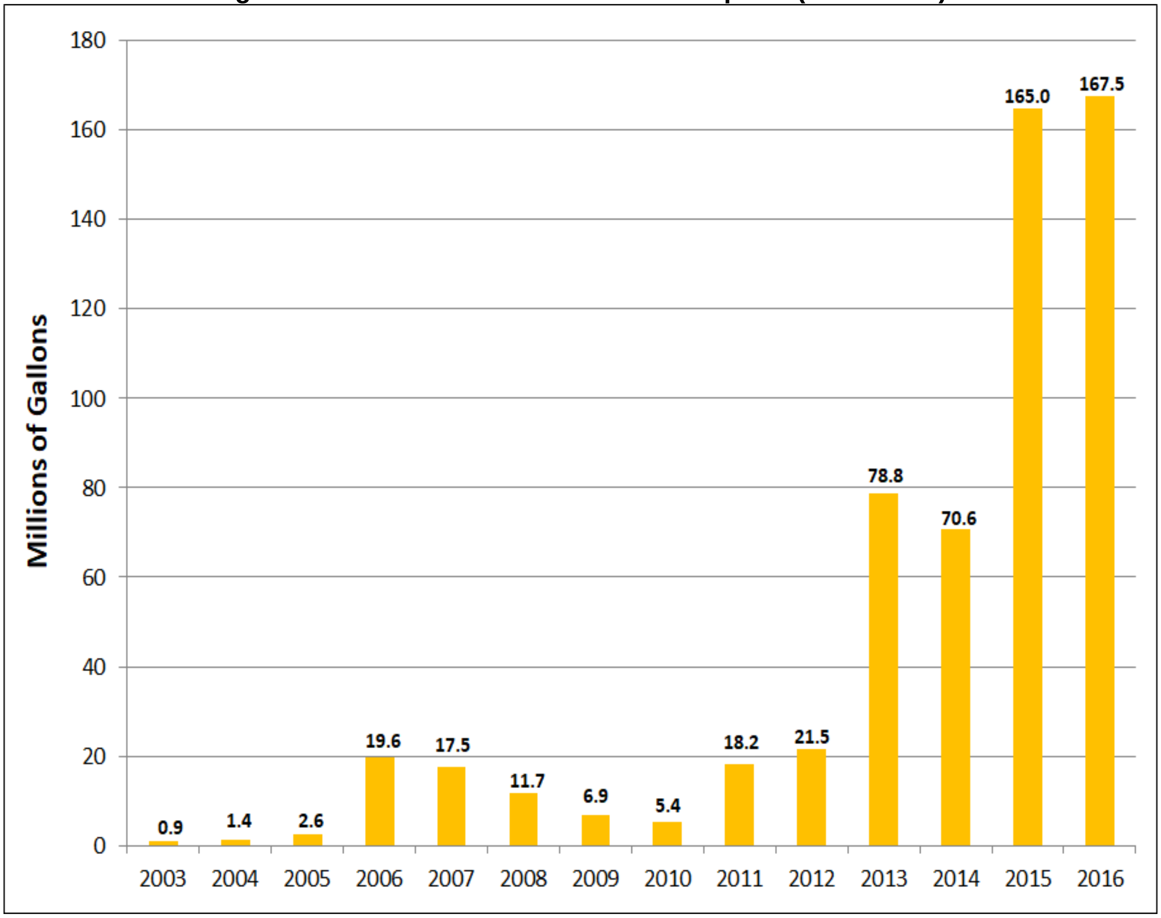



Source: Analysis of CARB LCFS data by Energy Commission.

## California Biodiesel Logistics

Biodiesel use in California has been modest prior to 2013 due to an inadequate level of distribution infrastructure (lack of storage tanks at terminals) and varying approaches and interpretations of regulations controlling the concentration of biodiesel that is permissible in Underground Storage Tanks (UST). As such, biodiesel used in California was no higher than 21 million gallons from 2003 through 2012, as depicted in **Figure 103**. Use over the last four years has steadily climbed to a record 167 million gallons (2016) as the distribution infrastructure improved and obligated parties under the state's LCFS turned to increasing quantities of biodiesel to help achieve compliance with their carbon deficit for both gasoline and diesel fuel sales.

Figure 103: California Biodiesel Consumption (2003–2016)




Sources: BOE, CARB, and Energy Commission analysis.

Infrastructure requirements for biodiesel are similar to those of ethanol in that biodiesel needs to be transported from points of production (both inside and outside California) to initial redistribution hubs via rail and marine vessels. Once inside California, the biodiesel must be hauled to distribution terminals that dispense diesel fuel destined for truck stops and other retail locations. The biodiesel infrastructure is adequate to allow an average blending level of nearly 5 percent by volume.[125] However, to enable an expansion of biodiesel use to an average concentration of 10 percent will likely require a combination of infrastructure investments (storage tanks and blending equipment) and possibly specific types of financial assistance to producers. One example of assistance could be some form of loan guarantee that enables producers to increase their purchase of feedstocks (higher monthly expenses). Even if a biodiesel producer has the equipment in place to produce more biodiesel, they may not have sufficient lines of credit to obtain a traditional loan to pay the higher up-front costs of expanded feedstock purchasing activities.

125 Biodiesel use in California diesel fuel during 2016 averaged 4.53 percent by volume, a significant increase from the average concentration of 0.65 percent during 2012.

Biodiesel is blended with diesel fuel as the tanker truck is loaded before delivery to the retail station. As such, the biodiesel must be stored in segregated tanks. Distribution terminal modifications will need to be made over the near- to mid-term to help enable sufficiently greater volumes of biodiesel for blending with conventional diesel fuel. New storage tanks will need to be constructed in most cases, although in some situations an existing storage tank can be converted from one type of fuel to biodiesel at a significantly lower cost and time frame. However, this approach would not be viable for most distribution terminals since all or most of the existing storage tanks are used continuously. If a terminal operator needs to install a new storage tank, the process to obtain a permit can be lengthy (as long as 12 to 18 months).

Biodiesel is imported into California from domestic and Canadian facilities. Rail cars brought 105.8 million gallons of biodiesel during 2016, or about 63.1 percent of total biodiesel imports. Rail imports have nearly tripled from 36.9 million gallons in 2013 when these represented 46.8 percent of total supply. There are no biodiesel rail facilities designed to handle unit trains. Rail receipts of biodiesel are normally transferred to tanker trucks via transloading, and the tanker trucks then transfer the biodiesel to distribution terminal storage tanks located throughout the state.

Additionally, biodiesel is imported into California by marine vessels. During 2016, 20.9 million gallons of biodiesel were imported via marine vessel (primarily from South Korea), representing 12.5 percent of the state's total supply. Although marine imports have increased in volume, their relative contribution has declined as a source of supply—dropping from 18.6 percent in 2013. Due to cargo sizes that are normally smaller than ethanol, the storage tank requirements to unload the biodiesel are more modest. Optimal storage tank sizes are less than 10,000 to 50,000 barrels in size. Smaller storage tanks at marine terminals are normally reserved for lubricants, specialty solvents, and other chemicals that have limited demand volumes. Based on conversations with various biodiesel importers, these types of storage tank accommodations at marine import facilities are limited. Although availability of marine facilities to accommodate biodiesel imports may be somewhat limited, it is likely that the majority of incremental biodiesel supply over the near- to mid-term will be sourced from higher California production and greater quantities of rail imports, rather than marine vessel imports.

As with ethanol logistics, few distribution terminals have the ability to receive shipments via rail. Therefore, most or all of the biodiesel would first need to be delivered to distribution terminals via tanker trucks to segregated storage tanks. The volume and associated trucking requirements for biodiesel are less than that for ethanol, with biodiesel volumes in 2016 being 10.7 percent that of ethanol. Assuming typical trucking logistics, roughly one-tenth the number of tanker trucks needed to transport ethanol would be necessary to distribute biodiesel to California distribution terminals. Although a doubling of biodiesel use would increase the requirements for additional trucking assets, that larger fleet would still be one quarter the size of the trucking assets used to distribute ethanol and only two percent the number of tanker trucks needed to transport gasoline to retail stations.

As biodiesel use continues to grow in the United States, so too do strategies for reducing the transportation costs of biodiesel. By far, pipeline delivery costs are the lowest of any of the primary methods of delivery, usually one tenth of the cost compared to tanker truck delivery. The primary concern of transporting biodiesel blends in mixed petroleum product pipeline systems is the potential contamination with jet fuel. As an example, Colonial Pipeline lists biodiesel as a "prohibited additive" that may not be shipped through their product pipeline system with the sole exception of Line #17, a portion of their pipeline system that does not handle any jet fuel.[126] Another example is the distribution of B5 (diesel fuel containing biodiesel up to a concentration of 5 percent by volume) on Kinder Morgan's Oregon Pipeline originating in Portland[127] and terminating in Eugene.[128] Since all of the Kinder Morgan petroleum product pipeline systems in California are used to ship jet fuel, it is unlikely that this practice could be adopted for use in this state. Over time, if the potential concern of jet fuel contamination with biodiesel can be overcome, the primary logistical impact would be the reduced need for delivery of biodiesel to distribution terminals via tanker trucks.

## Biodiesel Retail and Storage Logistics

Retail diesel fuel dispensers and USTs are certified to handle diesel fuel that contains biodiesel at concentrations of up to 5 percent by volume. However, these same USTs have not received independent testing organization approvals for biodiesel blends greater than B5 and up to B20. To provide additional time for these approvals to be developed, the State Water Resources Control Board (SWRCB) issued emergency regulations that took effect on June 1, 2009, allowing for a 36-month variance from this UST requirement.[129] This initial action removed a potential challenge to expanded use of biodiesel in California. However, the variance period passed without Underwriters Laboratories approval necessitating the promulgation of new regulations by the SWRCB during April 2012 to allow UST owners to obtain letters from manufacturers certifying material compatibility, referred to as an Affirmative Statement of Compatibility by Manufacturer.[130] The new regulations went into effect during June 2012 and now include all blends of biodiesel up to B100.[131]

## Issues—Biodiesel Blending Limits—Alternative Diesel Fuel Regulation

The CARB has promulgated a Final Regulation Order for Regulation on Commercialization of Alternative Diesel Fuels. The Office of Administrative Law approved the rulemaking and filed it

126 *Section 3, Product Codes and Specifications*, Colonial Pipeline Company, revised March 13, 2016, sections 3.2.8 and 3.2.10. A link to the document is as follows: http://www.colpipe.com/docs/default-source/tariff-archive/product-specifications-effective-march-2016.pdf?sfvrsn=4.

127 Actual injection point for 8-inch pipeline to Eugene is the Willbridge Terminal. A link to the terminal description is as follows: https://www.kindermorgan.com/pages/business/products_pipelines/terminals_w_willbridge.aspx\.

128 Specifications for B-5, Kinder Morgan, section 6.3, page 1, revised November 18, 2016. A link to the document is as follows: file:///C:/Users/Gordon%20Schremp/Downloads/6.3%20Distillates%20and%20Miscellaneous.pdf.

129 A link to a copy of the SWRCB regulatory action and Office of Administrative Law (OAL) approval are as follows: http://www.waterboards.ca.gov/water_issues/programs/ust/regulatory/biodiesel/oal_file2009_0521_02e.pdf.

130 A link to the State Water Resources Control Board filing is as follows: http://www.waterboards.ca.gov/water_issues/programs/ust/regulatory/docs/2012alt_mthd.pdf.

131 Compliance for Biodiesel Storage in USTs, California Biodiesel Alliance. A link to this site is as follows: http://californiabiodieselalliance.org/page5/page5.html.

with the California Secretary of State on November 16, 2015.[132] The intent of the regulation is to mitigate the potential emissions of nitrogen oxides associated with the use of biodiesel with diesel fuel. The requirements go into effect on January 1, 2018, and will limit the maximum permissible concentration of biodiesel to 10 percent by volume from November 1 through March 31 of each year following January 2018, until expiration of this provision that is estimated to be occur sometime during 2022. It also restricts usage to 5 percent by volume from April 1 through October 31.[133] It is uncertain whether entities that distribute biodiesel blends will attempt to switch back and forth between the two maximum permissible volume limits. If so, California's biodiesel concentration limit could effectively be 5 percent by volume by 2018, a slight increase from the 4.53 percent achieved during 2016. Further, some distributors that are currently dispensing biodiesel blends of up to 20 percent by volume would be unable to continue this practice after 2017.

There is no specific sunset date for this regulation because there is uncertainty when conditions will be achieved, enabling elimination of these biodiesel blending limits. Those provisions have to do with the transition to newer heavy-duty diesel vehicle engines and require a finding by the CARB Executive Officer that a sunset of the biodiesel in-use requirements will occur "When the vehicle miles travelled (VMT) by heavy-duty new technology diesel vehicles in California reaches 90 percent of total VMT by the California heavy-duty diesel vehicle fleet."[134] The California Biodiesel Alliance indicates that this milestone is forecast to be achieved by 2022, according to CARB staff.[135]

## Feedstock Availability for Incremental Biodiesel Supply

A number of biofuels have superior carbon intensity values that will be desirable to obligated parties trying to achieve compliance with the California LCFS. However, the potential production volumes for these fuels will ultimately be limited to availability of the necessary feedstocks.

### Corn Oil Biodiesel

During 2016, there were 1,306 million pounds of corn oil used as feedstock for biodiesel production.[136] Staff estimates that this quantity of corn oil yielded 169 million gallons of corn oil-based biodiesel in the United States, with California using 76.2 million gallons or 45 percent of the available domestic production.[137] At 5.5 $gCO_2e/MJ$, corn oil-based biodiesel used in

---

132 A link to the California Air Resources Board information on this subject is as follows: https://www.arb.ca.gov/regact/2015/adf2015/adf2015.htm.

133 *Final Regulation Order*, Attachment A, California Air Resources Board, Table A.1, page A-19/A-40. A link to this regulation is as follows: https://www.arb.ca.gov/regact/2015/adf2015/adffinalregorder.pdf.

134 Ibid., page A-20/A-40.

135 Alternative Diesel Fuel Regulation, California Biodiesel Alliance. A link to this site is as follows: http://www.californiabiodieselalliance.org/page7/code-3/index.html.

136 *Monthly Biodiesel Production Report*, U.S. EIA, February 28, 2017, Table 3. A link to this information is as follows: https://www.eia.gov/biofuels/biodiesel/production/archive/2016/2016_12/table3.pdf.

137 *California Modified GREET Pathway for the Production of Biodiesel from Corn Oil at Dry Mill Ethanol Plants*, California Air Resources Board, Release Date: December 14, 2010, page 8. A link to the document is as follows: http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/121410lcfs-cornoil-bd-rpt.pdf. Conversion of corn oil to biodiesel uses the following assumptions: Each 1.04 pounds of corn oil can yield 1.00 pounds of biodiesel. Density of biodiesel is 3,361 grams per gallon which converts to 7.4097 pounds per gallon.

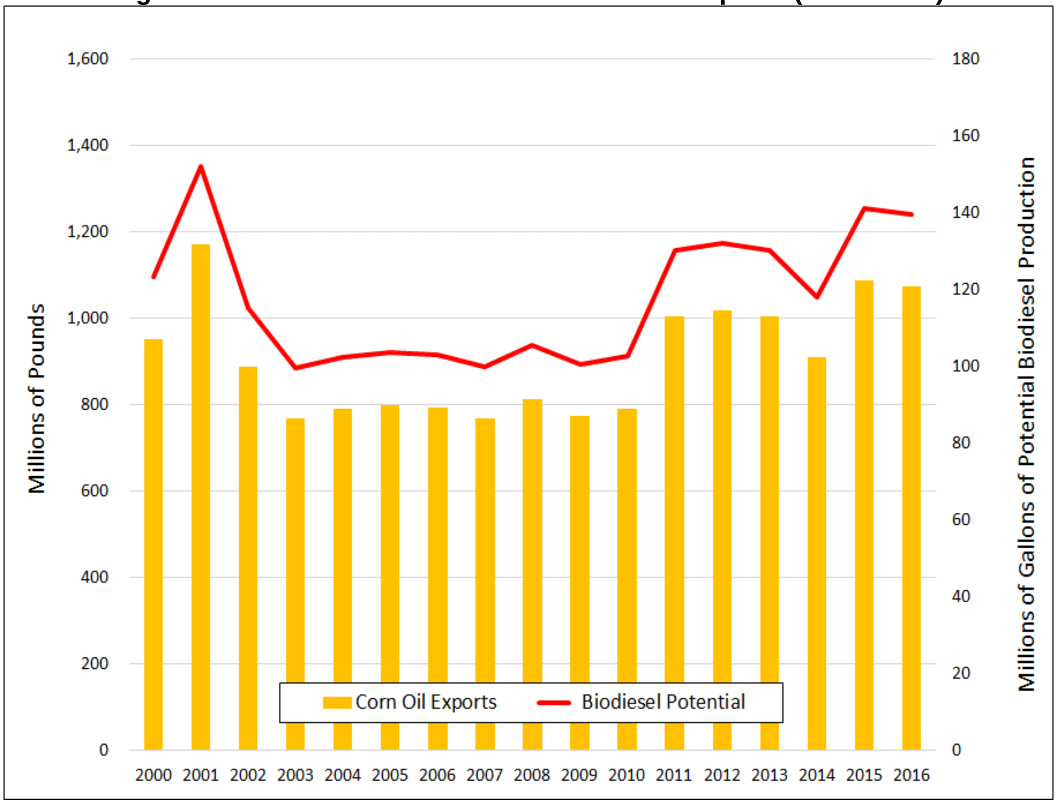
California during 2016 had the lowest carbon intensity of any biodiesel.Incremental corn oil-based biodiesel supplies could be obtained by importing additional production into California, converting corn oil exports into biodiesel, and converting all other uses of corn oil to biodiesel. Additional potential domestic imports of corn oil-based biodiesel are estimated at 92.8 million gallons for 2016. Exports of corn oil from the United States totaled 1,075 million pounds during 2016 which could have been converted to 140 million gallons of corn oil-based biodiesel.[138] **Figure 104** shows the theoretical quantities of exported corn oil biodiesel potential between 2000 and 2016.

It is unlikely that all of these corn oil exports would be converted to biodiesel since their demand is serving various types of product needs that could command higher prices. Even greater quantities of biodiesel could be produced if other domestic uses of corn oil were forgone or replaced with other oil crops. During 2016 there were 5,550 million pounds of corn oil produced with the aforementioned 1,075 million pounds exported, and another 1,306 million pounds used for domestic biodiesel production leaving a balance of 3,169 million pounds that could have been converted to 428 million gallons of corn oil-based biodiesel during 2016. This is probably unrealistic since refined corn oil is used to produce higher value products such as salad or cooking oil, and the infrastructure capacity to receive and convert corn oil to biodiesel is not developed to handle four times the current quantities of corn oil. Also, a portion of this corn oil is used as a feedstock to create renewable diesel fuel, discussed below, decreasing this upper limit of this estimate.

---

138 *Fats & Oils: Oilseed Crushings and Peanut Stocks and Processors*, United States Department of Agriculture, National Agricultural Statistics Service, March 29, 2017, Table 31. A link to the table is as follows: https://www.ers.usda.gov/webdocs/DataFiles/52218/table31.xls?v=42823.

**Figure 104: Biodiesel Potential from Corn Oil Exports (2000–2016)**




Source: Analysis of U.S. Department of Agriculture data.

Additional corn oil is being extracted at ethanol production facilities through the use of corn oil extraction equipment. The CARB estimates that for every 100 gallons of ethanol produced from corn, between 6 percent and 7 percent of that volume could be extracted in the form of corn oil using two extraction systems.[139] This means that the theoretical upper limit of corn oil from corn-based ethanol plants could range between 900 million and 1.05 billion gallons per year.[140] However, this extraction activity is already well underway and estimated to be deployed at 95 percent of all U.S. ethanol production facilities.[141] FEC Solutions estimates that 2,248 million pounds of corn oil were extracted from ethanol facilities during 2015.[142] Incremental corn oil supply from ethanol plants is therefore considered minimal at best, absent improved efficiency of extraction processes.

139 *California Modified GREET Pathway for the Production of Biodiesel from Corn Oil at Dry Mill Ethanol Plants*, California Air Resources Board, Release Date: December 14, 2010, page 8. A link to the document is as follows: http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/121410lcfs-cornoil-bd-rpt.pdf.

140 This range assumes that the upper limit of corn-based ethanol production will be 15.0 billion gallons per year, the maximum volume that may be used by obligated parties under the federal RFS2 program. Six percent of this volume equates to 900 million gallons of corn oil biodiesel and 7 percent equates to 1.05 billion gallons of corn oil biodiesel.

141 *Overview of Distillers Oil and Feed Fat*, FEC Solutions, April 2016, slide 14. A link to the presentation is as follows: http://www.biodieselsustainability.com/wp-content/uploads/2016/04/3._riley_distillers-corn-oil.pdf.

142 Ibid., slide 30.

### Used Cooking Oil Biodiesel

During 2016 there were 1,389 million pounds of used cooking oil (UCO) used as a feedstock for biodiesel production.[143] Staff estimates that this quantity of UCO yielded 160 million gallons of UCO-based biodiesel in the United States, with California using 35.3 million gallons or 22 percent of the available domestic production.[144] UCO-based biodiesel used in California during 2016 had the second lowest carbon intensity of any biodiesel at 16.0 gCO2e/MJ.

The theoretical availability of UCO-based biodiesel could be as great as 3.0 billion gallons per year for the entire United States, if one assumes that the waste oil from every hotel and restaurant is collected and processed into biodiesel.[145] This scenario is doubtful due to the inverse relationship between collection costs and size of supply.

### Animal Fats Biodiesel

During 2016 there were 1,202 million pounds of animal fats used as a feedstock for biodiesel production.[146] Staff estimates that this quantity of animal fats yielded 156 million gallons of animal fats-based biodiesel in the United States, with California using only 2.6 million gallons or 1.7 percent of the available domestic production.[147] Animal fats-based biodiesel used in California during 2016 had a carbon intensity of 39.4 gCO2e/MJ. It is not surprising that such a small portion of this type of biodiesel was used in California due to its higher carbon intensity relative to above-mentioned fuels. The incremental supply of animal fats that could be diverted as feedstock to produce biodiesel is not quantified but not as important as other lower carbon intensity feedstocks discussed above, which are expected to rise as a percentage of supply to help meet California's LCFS obligations. Animal fats and fish oils are a more significant feedstock resource to produce renewable diesel as is discussed below.

## Other Emerging Fuels

Renewable fuels are a subset of alternative fuels that are made from renewable feedstock, typically of biological origin, such as corn, soybeans, wood, and a variety of waste products including food waste, municipal solid waste, and landfill deposits. All renewable fuels except biomethane and renewable hydrogen are liquid fuels that would be used as substitutes for gasoline or diesel. Biomethane is a gaseous fuel that is a perfect substitute for either compressed or LNG, both of which are used as diesel substitutes.

---

143 *Monthly Biodiesel Production Report*, U.S. EIA, February 28, 2017, Table 3. A link to this information is as follows: https://www.eia.gov/biofuels/biodiesel/production/archive/2016/2016_12/table3.pdf.

144 Conversion of used cooking oil (UCO) to biodiesel uses the following assumptions:

Each 1.174 pounds of UCO can yield 1.00 pounds of biodiesel.

Density of biodiesel is 3,361 grams per gallon which converts to 7.4097 pounds per gallon.

145 *Learn About Biodiesel*, U.S. EPA, Region 9. A link to this site is as follows: http://www.epa.gov/region9/waste/biodiesel/questions.html.

146 *Monthly Biodiesel Production Report*, U.S. EIA, February 28, 2017, Table 3. A link to this information is as follows: https://www.eia.gov/biofuels/biodiesel/production/archive/2016/2016_12/table3.pdf.
Animal fats consisted of poultry, tallow, white grease, and other.

147 Conversion of animal fats to biodiesel uses the following assumptions:
Each 1.04 pounds of animal fats can yield 1.00 pounds of biodiesel. Density of biodiesel is 3,361 grams per gallon which converts to 7.4097 pounds per gallon.

Of the emerging renewable transportation fuels, only renewable diesel fuel and biomethane have been produced in commercial quantities or are likely to be produced in increasing volumes to help comply with the LCFS. There is a great deal of effort going into research and development of other fuels, but at present a great deal of uncertainty surrounds the future viability of these emerging fuel types.

### Renewable Diesel Fuel

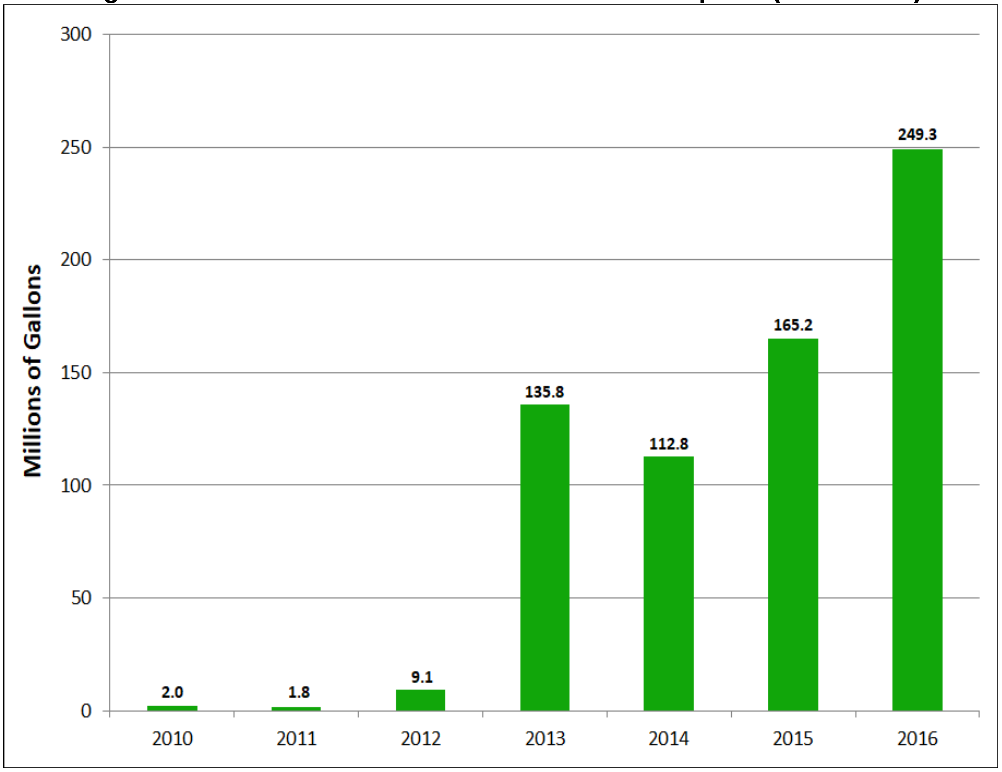
Renewable diesel, renewable jet fuel, and renewable gasoline are appealing because they are renewable fuels identical to the petroleum-based products they would replace. Consequently, they are sometimes also referred to as "drop-in" fuels. Only renewable diesel is currently produced in commercial quantities and is expected to be needed for compliance with the LCFS.

Renewable diesel can be made from a variety of feedstocks and is typically processed in a refining facility where the feedstocks are transformed into a diesel fuel through hydrocracking and hydrogenation. The refinery-based process produces a renewable diesel fuel that is chemically identical to diesel fuel, requiring no modifications for infrastructure or diesel engines. Renewable diesel production facilities are typically larger in capacity when compared to a typical biodiesel production facility.

California's use of renewable diesel is a recent development, with modest volumes prior to 2013 as depicted in **Figure 105**. But use over the last four years has steadily climbed to reach a record 249 million gallons by 2016 as additional production facilities came online and obligated parties under the state's LCFS turned to increasing quantities of renewable diesel to help achieve compliance with their carbon deficit for both gasoline and diesel fuel sales.

Sources for renewable diesel fuel are much more limited compared to biodiesel and ethanol. California currently has two sources of renewable diesel originating from facilities operated by Kern Oil and AltAir Paramount. Domestic imports have been received from Diamond Green Diesel and REG Geismar, both facilities located in Louisiana. The sole foreign source has been from Neste's facility in Singapore.

**Figure 105: California Renewable Diesel Consumption (2010–2016)**




Sources: CARB and Energy Commission analysis.

Diamond Green Diesel's facility in Norco, Louisiana, has an annual renewable diesel production capacity of approximately 150 million gallons per year and can process up to 1.3 billion pounds of animal fats and oils.[148] The company has plans to expand the facility to a capacity of 275 million gallons per year, scheduled for completion by the second quarter of 2018.[149] The future capacity of this plant alone will be nearly equivalent to the total quantity of renewable diesel fuel used in California during 2016.

Neste Oil has a combined renewable diesel production capacity of 675 million gallons per year from biorefineries in Finland, Singapore, and the Netherlands.[150] The Neste refinery in Singapore is the largest renewable diesel refinery in the world, with a production capacity of 264 million gallons per year.[151] According to the U.S. EIA's company level foreign import data, there were 194 million gallons of renewable diesel fuel imported from Singapore during 2016.[152] If the Neste

---

148 A link to Diamond Green Diesel's website is as follows: https://www.diamondgreendiesel.com/.

149 *Diamond Green Diesel Expanding to 275M Gallon Capacity to Meet Booming Renewable Diesel Demand*, Biofuels Digest, March 19, 2017. A link to the article is as follows: http://www.biofuelsdigest.com/bdigest/2017/03/19/diamond-green-diesel-expanding-to-275m-gallon-capacity-to-meet-booming-renewable-diesel-demand/.

150 *NExBTL® Renewable Diesel Singapore Plant*, California Air Resources Board, page 1. A link to the document is as follows: https://www.arb.ca.gov/fuels/lcfs/2a2b/apps/neste-aus-rpt-031513.pdf.

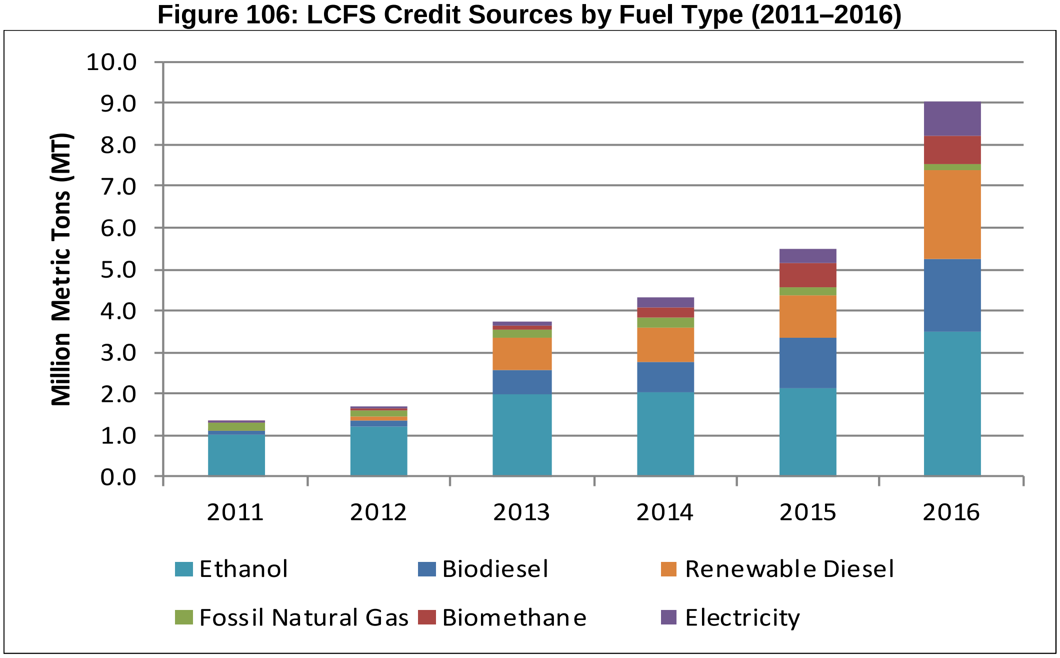
151 *Neste Oil's Singapore Refinery – the World's Largest and Most Advanced*, Neste Oil. A link to the document is as follows: https://ir-service.appspot.com/view/ahBzfmlyLXNlcnZpY2UtaHJkchsLEg5GaWxlQXR0YWNobWVudBiAgIChkZSmCQw.

152 *Company Level Imports Archives*, U.S. EIA. A link to the 2016 dataset is as follows: https://www.eia.gov/petroleum/imports/companylevel/archive/2016/data/impa16d_prel.xls.

Note: Information is listed under "Other Renewable Diesel Fuel", product code 205.

facility in Singapore was assumed to have operated at capacity during 2016, then 73 percent of that facility's output was shipped to California. An additional 28 million gallons (or another 11 percent of the plant's maximum output) was delivered to Oregon, New Jersey, and Pennsylvania during the same period. California and Oregon shipments are in direct response to the LCFS programs active in both states. The relative importance of renewable diesel fuel is shown in **Figure 106** that depicts the growing contribution of renewable diesel fuel for LCFS credits used by obligated parties. Renewable diesel fuel accounted for 23.8 percent of all credits under the LCFS program during 2016 and 46.0 percent of the renewable liquid fuel credits, despite the fact that renewable diesel volumes only amounted to 15.8 percent of all renewable liquid transportation fuel (biodiesel, ethanol, and renewable diesel) volumes that year.

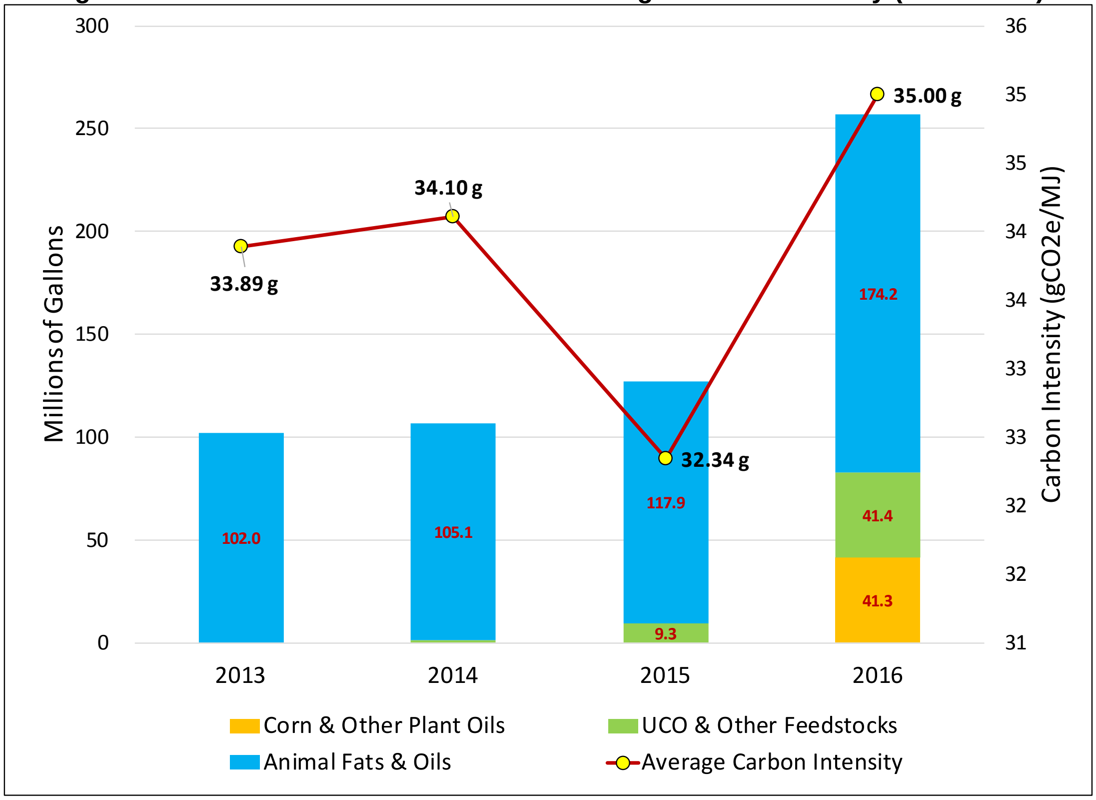
**Figure 106: LCFS Credit Sources by Fuel Type (2011–2016)**




Source: CARB.

The feedstocks used to create renewable diesel fuel for use in California are markedly different than those used to make biodiesel for use in California. **Figure 107** shows an initial predominance of animal fats and oils has given way to increased diversity as manufacturers continue to push greater use of corn oil feedstock, which has the lowest carbon intensity score of all renewable diesel fuel types.

Figure 107: California Renewable Diesel Average Carbon Intensity (2013–2016)




Sources: CARB and Energy Commission analysis.

Although renewable diesel fuel is chemically identical to diesel fuel, requiring no modifications to retail infrastructure or diesel engines, segregated wholesale rack infrastructure may be needed for renewable diesel.[153]

## Other Renewable Transportation Fuels

Other alternative transportation fuels, (such as conventional hydrogen, propane, CNG, and LNG), as well as other renewable transportation fuels (such as biomethane and renewable hydrogen) are not discussed in this report. The Fuels and Transportation Division of the Energy Commission has a number of programs and projects designed to help foster expanded penetration of various alternative and renewable transportation fuel infrastructure and use.[154] Highlighting just one example would be the recent public workshop held on January 30, 2017, that focused on renewable hydrogen developments and activities.[155]

---

153 *Neste Renewable Fuel Handbook*, Neste Oil, May 2016. A link to the document is as follows: https://www.neste.com/sites/default/files/attachments/neste_renewable_diesel_handbook.pdf.

154 A link to the Fuels and Transportation Division's information is as follows: http://www.energy.ca.gov/transportation/.

155 *Implementation Strategies for Production of Renewable Hydrogen in California*, California Energy Commission Public Workshop, January 30, 2017. A link to the presentations and associated material is as follows: http://www.energy.ca.gov/altfuels/2017-HYD-01/documents/2017-01-30_workshop/2017-01-30_presentations.php.

# CHAPTER 5: Transportation Fuel Price Analysis

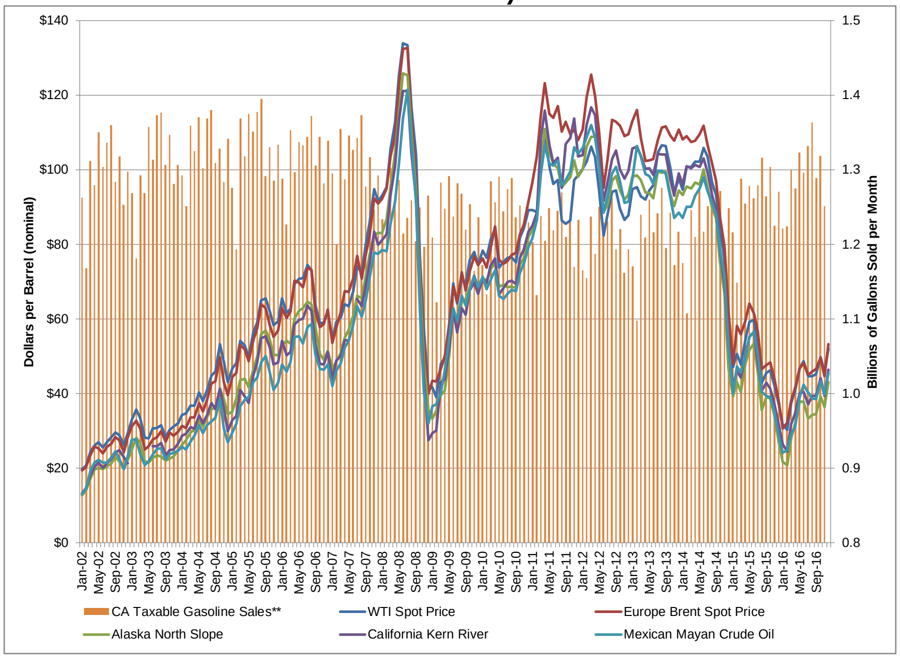
California does not produce all the crude oil it consumes. The state is part of a global market that purchases and imports crude oil to support its gasoline, diesel, and jet fuel consumption. Because of this, California gasoline, diesel, and jet fuel prices (and some alternative fuel prices) are directly related to the international price of crude oil, which changes based on world crude oil supply and demand fundamentals. California's supply and demand disposition directly influences refiner and retailer margins (or cost adders for their participation in the supply network).

## Crude Oil Price Analysis

The tie to the international markets is more clearly seen when crude oil spot prices are compared to California gasoline consumption. **Figure 108** shows Alaska North Slope, California Kern River, West Texas Intermediate (WTI), Mexican Mayan Crude, and European Brent prices with California gasoline consumption. As seen in **Figure 108**, all prices listed seem to be correlated and remain tightly grouped, with the exception of the 2011 to 2014 time period. Comparing these prices to California gasoline consumption in the **Figure 108**, sales and prices seem fairly unrelated with steady gasoline sales occurring from 2002 to 2007. Not until the sharp rise and fall of crude oil prices in 2008 did California gasoline sales fall. Even with the sharp reduction in prices by the beginning of 2009, monthly consumption remains roughly at its 2008 consumption levels until 2015, when a sharp reduction in crude oil prices lead to increased consumption in 2015 and 2016. While a direct correlation between California consumption and crude oil prices seems unclear, what is clear is that the listed crude oil prices are all highly related to each other as they appear to maintain steady relationship to one another: when one rises, the rest rise as well. This is likely due to most crude oil prices being indexed to WTI or Brent prices, leading to the conclusion that these prices are likely influenced by world crude oil supply and demand disposition.

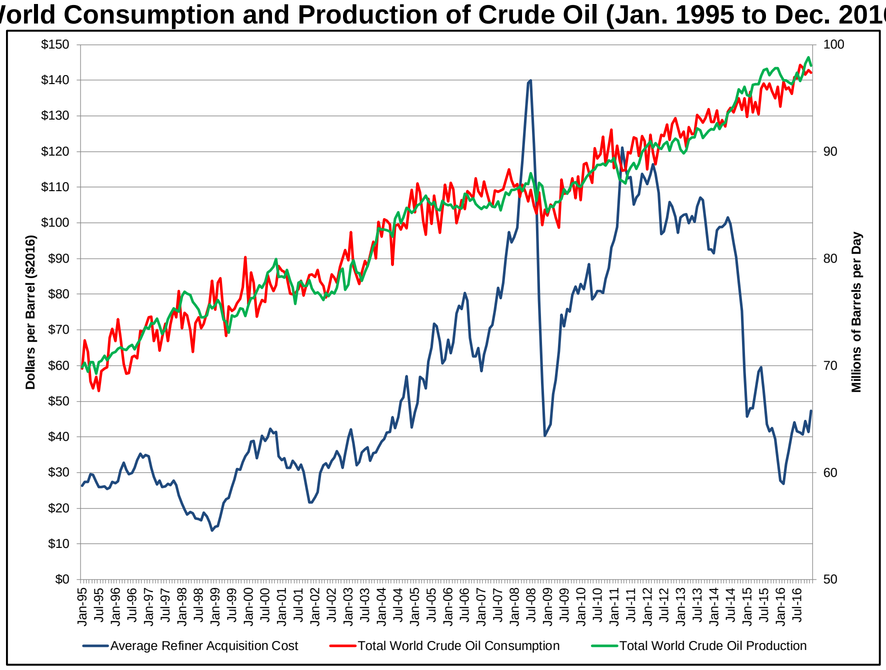
Despite the decline in California refinery usage of crude oil, world consumption of crude oil is continuing to increase (**Figure 109**). In 1995, world crude oil consumption averaged roughly 70 million barrels a day, but by 2016 it rose to an average of 97 million BPD and a compound average growth rate of 1.5 percent a year. During that same period, the average cost paid by United States refiners for crude oil changed dramatically, starting at $26 a barrel in 1995 and rising to a 30-year-average monthly high of $140 a barrel in July 2008. This led to a fall ($42 January 2009), rise ($91 February 2011), and fall ($28 February 2016) in crude oil prices from 2008 to 2016. While the refiner acquisition cost (RAC) of crude oil changed constantly, consumption and production increased steadily, with only the large swing in prices during 2008 appearing to have any effect, with consumption dropping from a monthly high of 88 million BPD in July 2008 to 84 million BPD in January 2009. While it appears that both world consumption and production have no influence on the price of crude oil, when the relative difference between the two are compared their relationship with price becomes apparent.

**Figure 108: Monthly California Taxable Gasoline Sales and Crude Oil Prices (Jan. 2002 to Dec. 2016)**




Source: U.S. EIA, Energy Commission, and Board of Equalization.

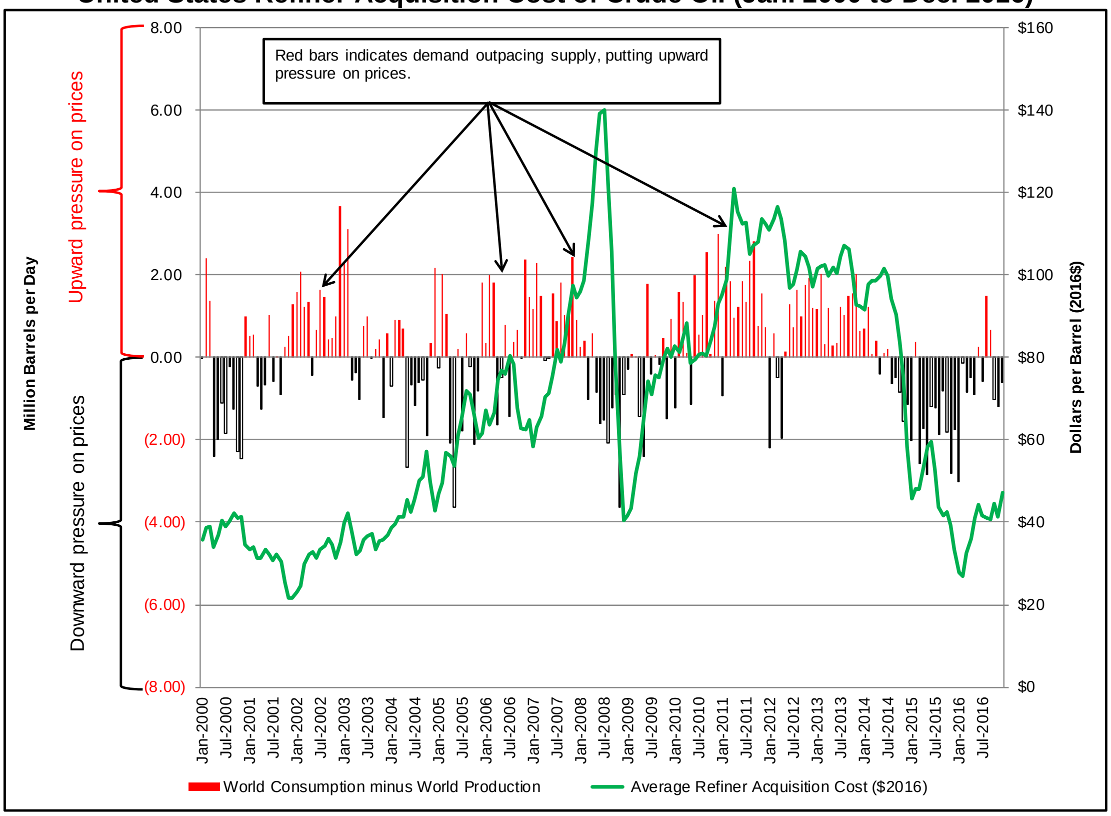
**Figure 109: Monthly United States Refiner Acquisition Cost of Crude Oil with World Consumption and Production of Crude Oil (Jan. 1995 to Dec. 2016)**




Source: U.S. EIA.

**Figure 110** shows the differences between the monthly world consumption and world production of crude oil, with red bars indicating that consumption in that month is greater than production. Black bars indicating that production is greater than consumption. Also shown in **Figure 110** is the average RAC in inflation adjusted 2016 dollars as a green line. Within this figure it is easier to see the classic economic supply and demand relationship in action, as periods of black bars (more production than consumption) are typically associated with the RAC falling. Periods which typify this relationship include April 2000 to April 2001, January 2012 to July 2012, and May 2014 to January 2016. This relationship also holds for the inverse, as a run of red bars (more consumption than production) seem to also be associated with an increasing RAC. These locations are marked within **Figure 110** and are: May 2001 to February 2003, January 2007 to June 2008, and July 2009 to November 2011. While this relationship seems to explain a great deal of why RAC is changing over time, there are two noticeable periods of time (April 2003 to December 2006 and July 2012 to January 2014) that do not seem to hold to this pattern. That is why there are still other items to take into account when looking at changes in price.

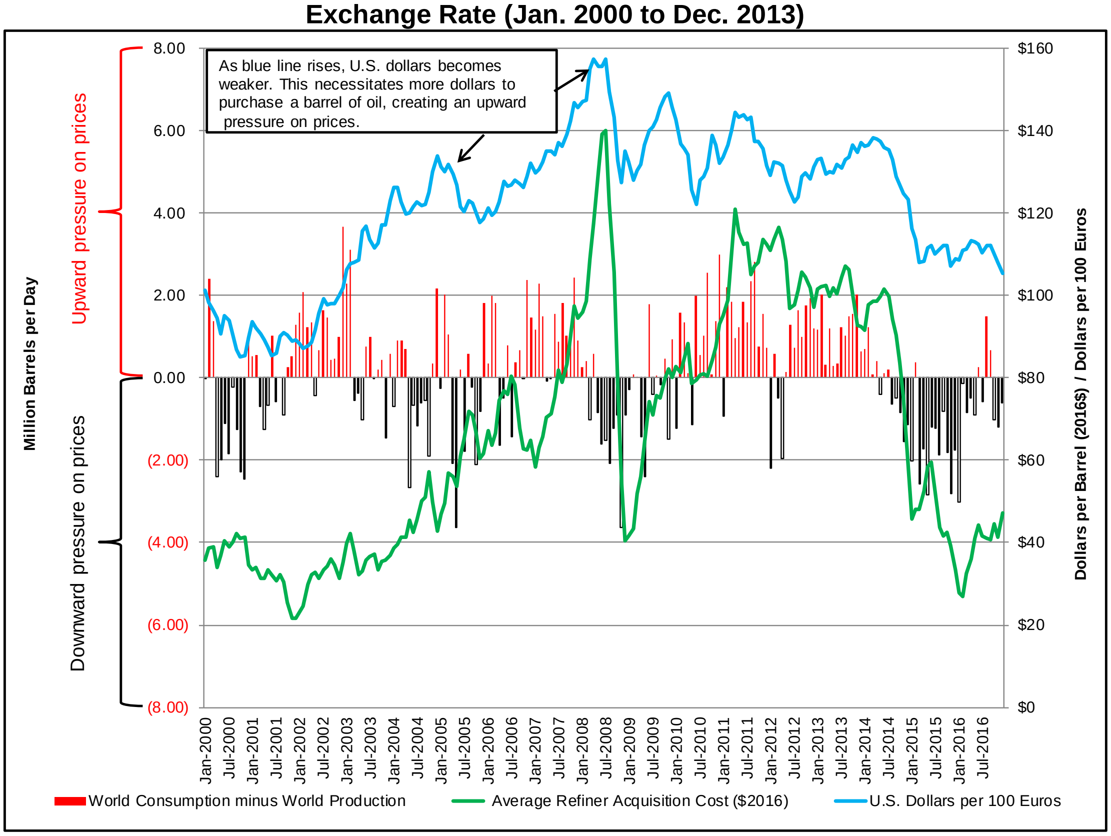
**Figure 110: Monthly Differences in World Crude Oil Consumption and Production, with United States Refiner Acquisition Cost of Crude Oil (Jan. 2000 to Dec. 2016)**




Source: U.S. EIA.

Since crude oil prices are set in an international market, exchange rates of national currencies need to be examined before conclusions about price changes can be made. Even though crude oil is traded in many different currencies, the United States dollar/euro exchange rate seems to be a representative benchmark for judging the United States dollar's purchasing power in the international market, as the euro is another currency in which oil is often traded. **Figure 111** is the same graph as shown in **Figure 110**, but here a blue line is added to show the United States dollar/euro exchange rate (here expressed as the amount of dollars needed to receive 100 euros in exchange). When this line rises the purchasing power of the dollar is weakening (more dollars needed to get a hundred euros) and vice versa. This weakening of the dollar leads to a reduction in the relative purchasing power of that dollar to buy crude oil, necessitating an increase in price in dollars to get the same amount of euros need to buy that product. Even if the item was not traded in euros, international dealers would likely see this relationship and demand a higher value to account for their payment being worth less when they attempt to trade for those euros or other currencies. If one assumes the United States dollar/euro is an indicator of the dollar's general purchasing power on the international market, it can be assumed that as that index rises, RAC would also increase as a response to the weakening position of the dollar. **Figure 111** displays this general relationship of a weakening dollar leading to higher RAC in United States dollars. During the period of April 2003 to December 2006, it is possible that this is a reason for RAC increasing despite a sustained period of world production outpacing world consumption.

**Figure 111: Monthly Differences in World Crude Oil Consumption and Production, with United States Refiner Acquisition Cost of Crude Oil and the United States Dollar per Euro Exchange Rate (Jan. 2000 to Dec. 2013)**



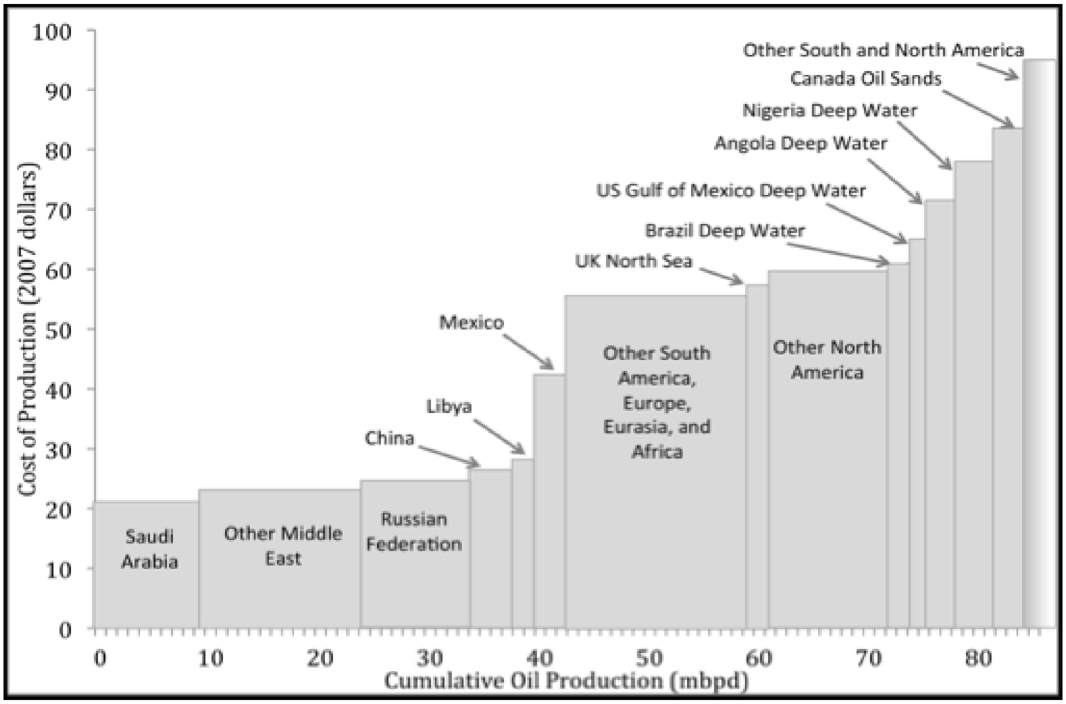

Source: U.S. EIA and the St. Louis Federal Reserve Bank.

A possible explanation of why crude oil prices increased at an accelerated rate from February 2007 to July of 2008 relative to the norm of the 2000s (4.8 percent compound average increase per month versus a one percent increase per month, respectively), is that world consumption of crude oil was greater than production and that a weakening of the U.S. dollar's purchasing power was occurring at the same time, which together applied a greater than normal upward pressure on prices. This may only be one of the reasons for that increase in growth, since soon after the record high monthly average price of $140.02 was set (in 2016 dollars) in July 2008, prices fell to $122.03 in August of 2008, then to $105.69 in September 2008, $78.35 in October 2008, $55.29

in November 2008, and $40.41 in December 2008 (a roughly 70 percent decrease over six months, at a compound average rate of 22 percent a month). The final trough of this downward trajectory occurred in January 2009 at $40.45 and this downward plunge in prices is generally seen as a result of the difficulties experienced by the world's financial markets during this period, which also signaled the beginning of the world recessionary period of that time. The inverse of this relationship also appears to hold, with a strengthening dollar leading to lower prices between July 2014 and January 2015. In July 2014, the average RAC price was $99.83 (2016 dollars) with the United States dollar/euro exchange rate trading at 1.35 dollars for one euro. In the subsequent six months, the exchange fell at an average rate of 2.5 percent per month to 1.16 dollars for one euro (dollar strengthening) and the price of RAC fell at an average rate of 12 percent per month to $45.71.

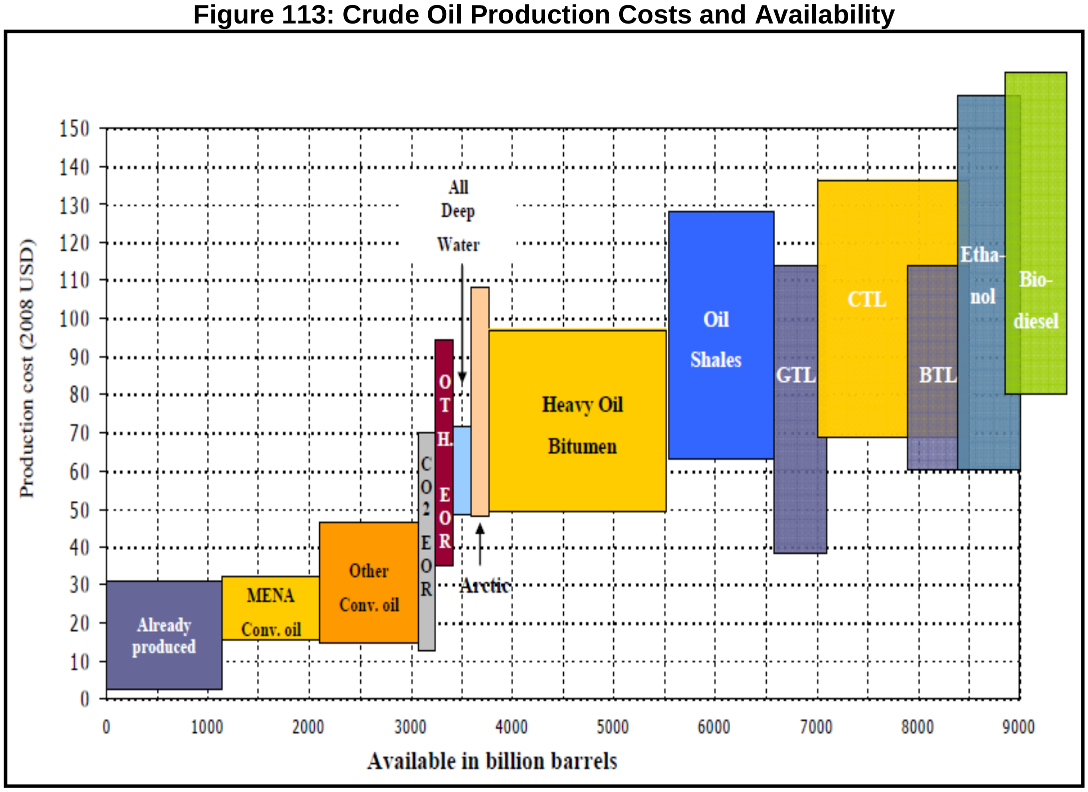
With the basic supply and demand story appearing to explain the long-term trends in crude oil prices (often referred to as market fundamentals), looking at long-term trends in production and consumption are important in long-term price scenario development. Lower-cost methods are diminishing, leading to the need for more expensive locations and methods to be deployed to meet consumption. This creates a constant upward pressure on prices. **Figure 112** and **Figure 113** show 2008 and 2009 estimates of crude oil production costs by different locations and production technologies. Both figures show that as higher levels of production are needed, more expensive locations and techniques are needed to be deployed to meet higher consumption levels. As a result, prices must rise to meet increased production costs. Upward pressure on prices can be offset by lower consumption of this resource. However, for reasons explained below, this might be difficult to achieve at the global level. Technology-based efficiency gains like directional drilling, which could lead to lower costs in extracting the resource, could lower the cost of production. It is unclear how quickly these jumps will occur and whether they align with market pressures.

**Figure 112: IHS Cambridge Energy Research Associates Cost of Production Estimates for Crude Oil**




Source: CERA. 2008. Ratcheting Down: Oil and the Global Credit Crisis.

**Figure 113: Crude Oil Production Costs and Availability**




Source: OECD/IEA 2009 via NRG Expert Energy Intelligence.

In the case of continued increases in overall world consumption, upward pressure in prices occurs from the need to move to more costly production methods to support increased demand for crude oil, especially as continued demand increases for crude oil from the development of non-Organization for Economic Co-operation and Development (OECD) countries. Shown in **Table 12** are the 10 most populous nations, as reported by the U.S. Census Bureau for 2016 and 1995. Only the United States and Japan are OECD members (likely fully developed economically). These two nations were ranked first and third among crude oil-consuming nations in the world in 2016, even though they were only the third- and tenth-most populous nations that year. The two most populous nations in the world, China and India, were ranked second and fourth among oil consuming nations in world. These levels of total consumption were a result of their immense populations, rather than their per capita consumption. In 2016, both nations were estimated to have over a billion people each, accounting for 36 percent of the total world population of 7.02 billion people. Yet, it is generally accepted that both of these nations are rapidly improving their economic output profile (see **Table 13**) and with that improvement, higher levels of per capita oil consumption is likely to occur.

**Table 12: World and National Population Estimates and Oil Consumption (for 2012 and 1995)**

| Countries and Areas Ranked by Population and Oil Statistics: 2016 | | | | |
|---|---|---|---|---|
| **Rank** | **Country or Area** | **Population** | **Per Capita (Gallons per Day)** | **Total Consumption (Million Barrels per Day)** |
| 1 | China | 1,373,541,278 | 0.36 | 11.92 |
| 2 | India | 1,266,883,598 | 0.13 | 3.86 |
| 3 | United States | 323,995,528 | 2.56 | 19.72 |
| 4 | Indonesia | 258,316,051 | 0.28 | 1.74 |
| 5 | Brazil | 205,823,665 | 0.66 | 3.25 |
| 6 | Pakistan | 201,995,540 | 0.10 | 0.46 |
| 7 | Nigeria | 186,053,386 | 0.06 | 0.29 |
| 8 | Bangladesh | 156,186,882 | 0.03 | 0.11 |
| 9 | Russia | 142,355,415 | 1.12 | 3.81 |
| 10 | Japan | 126,702,133 | 1.46 | 4.40 |
| | World | 7,323,187,457 | 0.55 | 96.64 |
| **Countries and Areas Ranked by Population and Oil Statistics: 1995** | | | | |
| **Rank** | **Country or Area** | **Population** | **Per Capita (Gallons per Day)** | **Total Consumption (Million Barrels per Day)** |
| 1 | China | 1,216,378,444 | 0.12 | 3.36 |
| 2 | India | 920,584,971 | 0.07 | 1.58 |
| 3 | United States | 266,278,393 | 2.80 | 17.73 |
| 4 | Indonesia | 197,603,427 | 0.17 | 0.81 |
| 5 | Brazil | 161,911,449 | 0.46 | 1.79 |
| 6 | Russia | 148,758,039 | 0.84 | 2.98 |
| 7 | Pakistan | 134,185,366 | 0.09 | 0.30 |
| 8 | Japan | 125,327,055 | 1.90 | 5.66 |
| 9 | Bangladesh | 121,442,312 | 0.02 | 0.05 |
| 10 | Nigeria | 109,752,901 | 0.11 | 0.28 |
| | World | 7,012,167,642 | 0.42 | 70.38 |

Source: U.S. Census Bureau and U.S. EIA.

**Table 13: World and National Per Capita Income Figures in United States Dollars (1995–2015, in 2016 dollars)**

| | | Bangladesh | Brazil | China | India | Indonesia | Japan | Nigeria | Pakistan | Russia | United States | World | Hong Kong SAR (China) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2016$ | 1995 | $492 | $9,360 | $1,352 | $692 | $2,448 | $44,447 | $1,363 | $899 | $6,517 | $42,585 | $8,086 | $24,106 |
| | 2000 | $562 | $9,612 | $1,951 | $848 | $2,360 | $46,430 | $1,411 | $936 | $7,147 | $49,608 | $8,931 | $25,341 |
| | 2005 | $661 | $10,368 | $3,015 | $1,081 | $2,780 | $48,879 | $2,055 | $1,077 | $9,830 | $53,681 | $9,753 | $30,486 |
| | 2010 | $837 | $12,245 | $5,021 | $1,482 | $3,441 | $49,004 | $2,549 | $1,149 | $11,753 | $53,261 | $10,440 | $35,838 |
| | 2011 | $881 | $12,603 | $5,474 | $1,559 | $3,606 | $49,044 | $2,602 | $1,156 | $12,245 | $53,702 | $10,636 | $37,312 |
| | 2012 | $927 | $12,725 | $5,875 | $1,626 | $3,773 | $49,877 | $2,642 | $1,171 | $12,655 | $54,480 | $10,769 | $37,506 |
| | 2013 | $971 | $12,989 | $6,300 | $1,712 | $3,932 | $50,964 | $2,711 | $1,197 | $12,789 | $54,987 | $10,903 | $38,487 |
| | 2014 | $1,017 | $12,888 | $6,725 | $1,814 | $4,078 | $51,218 | $2,806 | $1,227 | $12,652 | $55,853 | $11,065 | $39,224 |
| | 2015 | $1,071 | $12,287 | $7,154 | $1,927 | $4,221 | $51,914 | $2,806 | $1,258 | $12,154 | $56,855 | $11,223 | $39,828 |
| | CAGR for 95 to 15 | 3.97% | 1.37% | 8.69% | 5.25% | 2.76% | 0.78% | 3.68% | 1.69% | 3.17% | 1.46% | 1.65% | 2.54% |

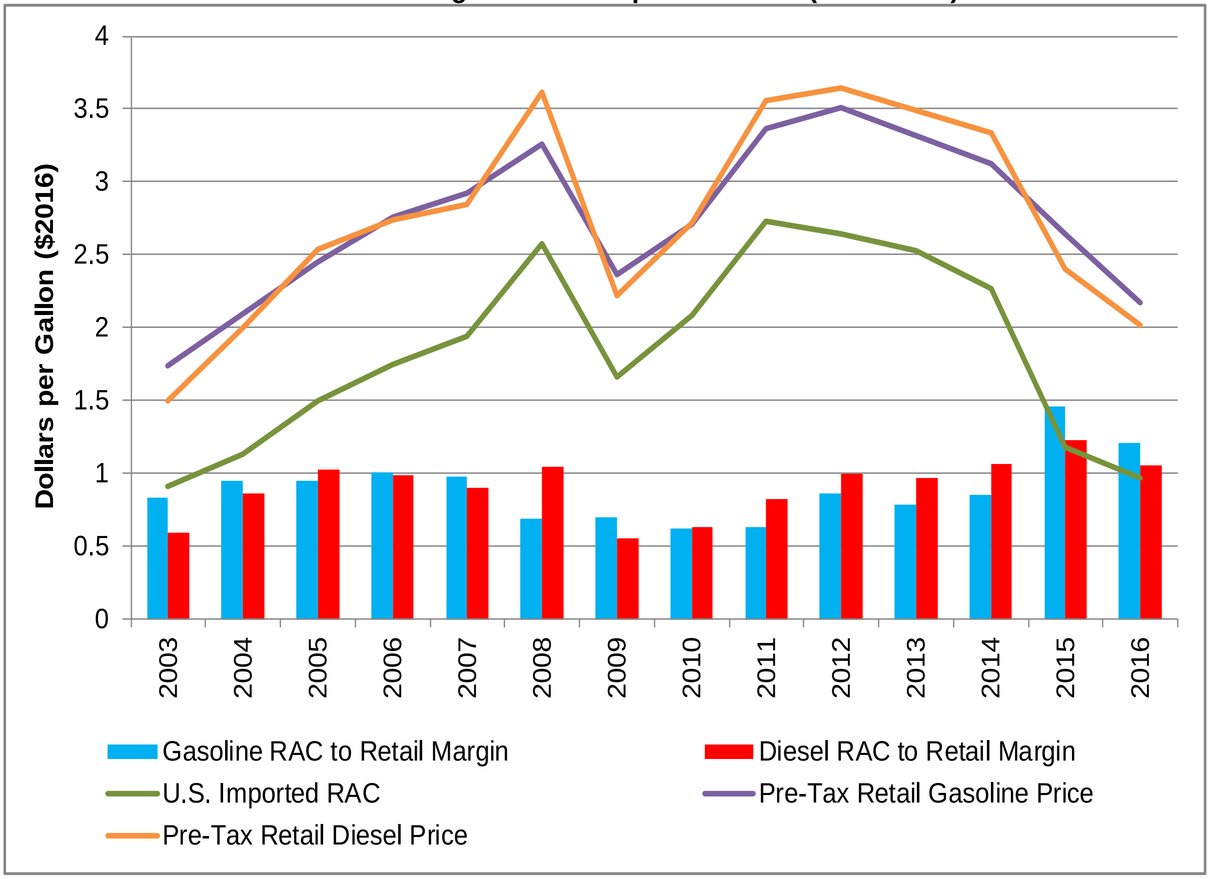
Source: U.S. Census Bureau and the World Bank.

If both these countries improve their economic outlook and thus increase per capita oil consumption to the same level as Japan in 2016, using 2016 population estimates, their oil consumption would increase to 47.7 million BPD for China, and 44.0 million BPD for India. The combined total of 91.7 million BPD would represent roughly 95 percent of total world consumption (96.64 million BPD). Assuming that these two nations are not the only ones seeking to improve their economy's output and that the world average per capita oil consumption was raised to 2016 Japanese values, again using 2016 population figures, world consumption of oil would increase to 254.6 million BPD of crude oil consumption, a consumption level 2.63 times that of the 2016 level.

## California Retail Transportation Fuel Trends

California consumption of petroleum has little influence on the world price of crude oil. Yet the question remains, does California consumption have any influence on the price of gasoline and diesel within the state? **Figure 114** displays RAC, the pretax price of both gasoline and diesel, as well as the differences between the RAC and the pretax price of the fuels (RAC-to-retail margin). The figure shows both monthly pretax gasoline and diesel prices rose and fell in a generally symmetrical pattern to that of crude oil. Because of this relationship, the difference between crude oil prices and pretax retail prices for both gasoline and diesel has been relatively stable on an annual basis, at least in comparison to changes in crude oil prices. While not perfectly constant over the 2003 to 2016 time span (analysis starts in 2003 due to this being the first year MTBE was phased out in California), the RAC-to-retail margin of gasoline has varied from an annual average minimum of $0.62 (2011) to an annual average maximum of $1.38 (2015), in inflation-adjusted 2016 dollars. Over that same period, gasoline prices, with taxes, reached an annual average minimum of $2.36 (2003) to an annual average maximum of $4.19 (2012), in inflation-adjusted 2016 dollars. It should also be noted that decreases in margins occurred following the United States financial crisis that began in late 2008, and it was this decrease that yielded the low margin results of this analysis. This period also seems to be the biggest contributor to the variation in margins over this time period.

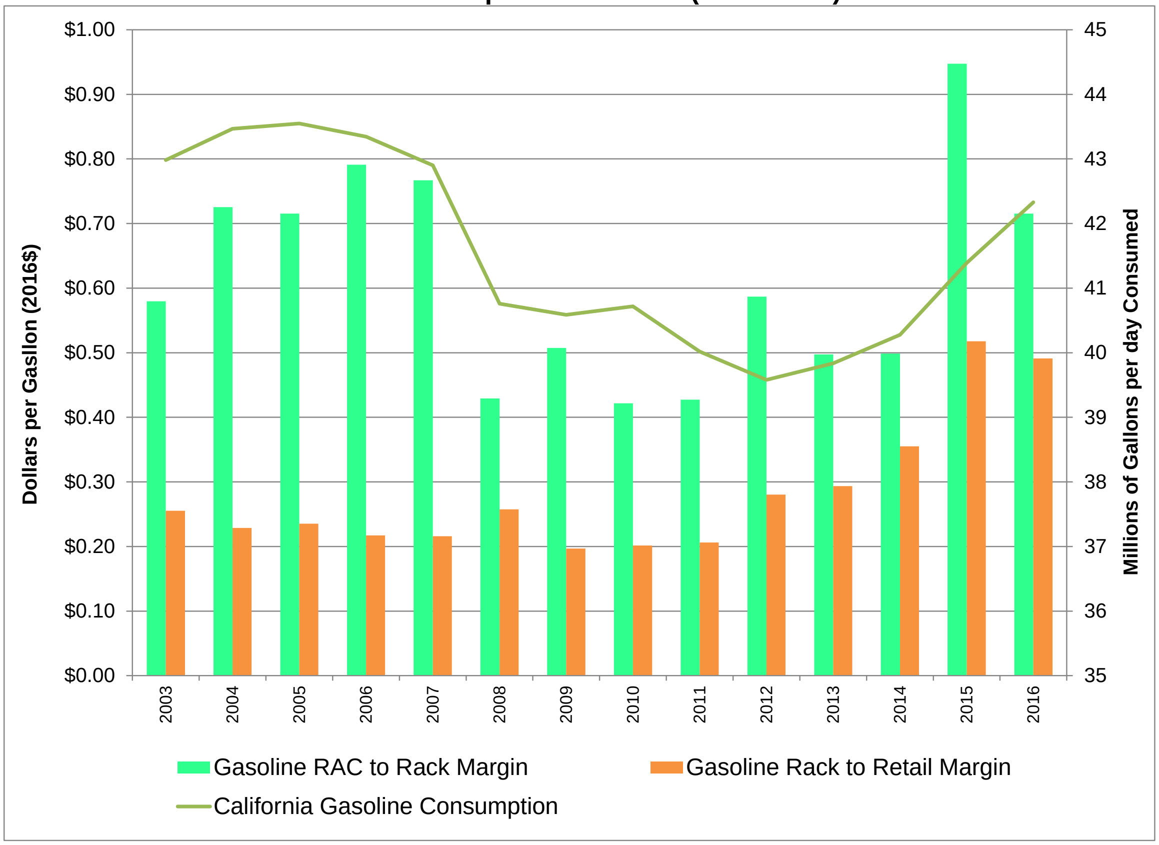
**Figure 114: Annual Pretax California Gasoline and Diesel Prices with United States Average Refiner Acquisition Cost (2003–2016)**




Source: U.S. EIA.

Upon closer inspection of the margins, the California RAC-to-rack gasoline margin (or refiner margin) appears to respond to changes in the consumption of gasoline in California. In **Figure 115**, years with higher daily gasoline consumption appear to correspond with higher annual average refiner margins. 2003 to 2007 represent some of California's highest per day gasoline consumption years and correspond to some of California's highest refiner margin years. Furthermore, 2008 to 2014 are all low gasoline consumption years with some of the lowest refiner margins. While 2015 is the highest annual average refiner margin year, this high mark is likely a result of the Torrance Refinery accident that left that refinery unable to process crude until halfway through the following year. Unlike the refiner margin, the rack-to-retail margin (or dealer margin) remained extremely steady at roughly $0.20 (2016 dollars) from 2003 to 2011. From 2012 to 2016, the dealer margin has steadily grown to roughly $0.50 in 2015 and 2016. This development was singled out in Energy Commission Petroleum Market Advisory Committee meetings, but no cause for this increase was identified.

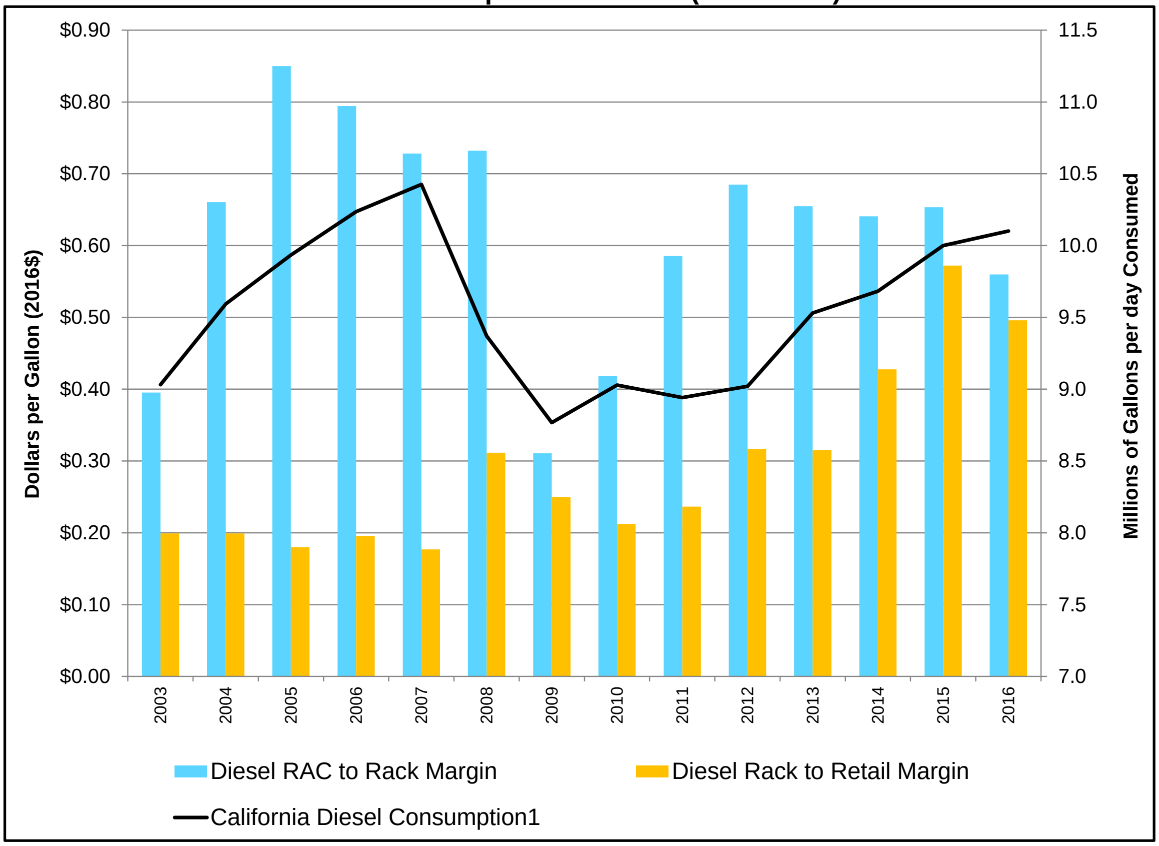
**Figure 115: Annual California Gasoline Refiner and Retailer Margins with Consumption Estimates (2003–2016)**




Source: U.S. EIA and Energy Commission.

Unlike gasoline, California refiner margins for diesel seem less responsive to annual changes in diesel consumption (**Figure 116**). While refiner margins increased overall from 2003 levels between 2003 and 2007 with an increase in consumption, 2005 stands out as a high for that period—with the margin falling going into 2006 and 2007. Also, diesel margins returned fairly quickly to the $0.60 to $0.70 (2016$) range by 2012, even without a return to prerecession diesel consumption levels. It wasn't until 2013 that diesel consumption noticeably grew—with consumption growing at a compound average growth rate of 2.9 percent a year from 2012 to 2016. However, diesel refinery margins fell from $0.68 to $0.56 between 2013 and 2015, averaging roughly $0.65. Like gasoline, diesel retainer margins display the same growth pattern. Starting in 2011 and increasing at a compound average growth rate of 16 percent, diesel retailer margins moved from $0.24 in 2011 to $0.50 in 2016 (high of $0.57 in 2015).

**Figure 116: Annual California Diesel Refiner and Retailer Margins with Consumption Estimates (2003–2016)**



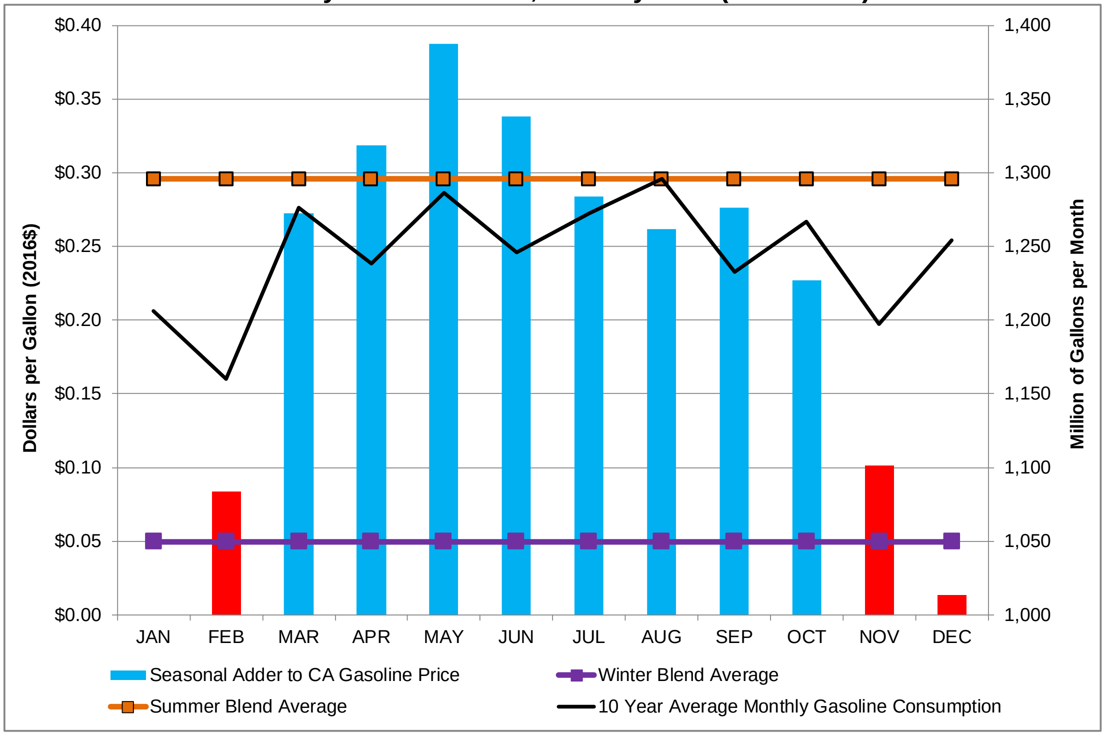

Source: U.S. EIA and Energy Commission.

1 Diesel consumption figures graphed on this figure include off-road and nontaxable amounts of diesel consumption

Also readily seen in the data is that during months when summer blend gasoline is sold, gasoline margins rise noticeably in comparison to months when winter blend gasoline is mandated. Shown in **Figure 117** is a simple month-and-year time effects regression estimate of the increase in margins, relative to the month of January (RAC is the only other independent variable in the model).[156] Per this analysis, summer blend gasoline months tend to raise the margin on gasoline by roughly $0.25 in comparison to winter gasoline months. This change in pricing makes sense because summer blend months are also months that typically see higher gasoline consumption from increased travel due to warmer weather and this regression estimate is likely estimating the increase in pricing from that added demand as well.

156 Regression model specification: Pretax gasoline price = f{RAC, Month boolean variables, Year boolean variables}. R-squared for this regression was 0.938, with the intercept, RAC, and all summer month boolean variables being statistically significant at a 99 percent level. All winter months failed to be significant at least a 90 percent level.

**Figure 117: Regression Estimated Monthly Gasoline Price Differences from an Average January Gasoline Price, Monthly Data (2003–2016)**

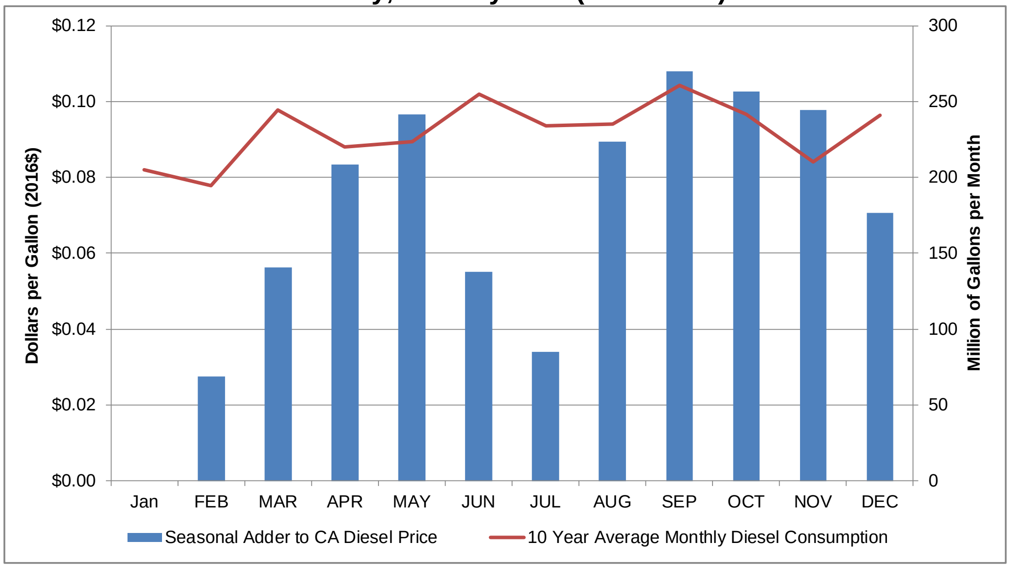



Source: Energy Commission.

Refiners are also required to lower the Reid Vapor Pressure (RVP) of gasoline from between 10.5 to 14.0 RVP (actual winter RVP of gasoline depends on the winter month and pipeline it travels on) to 5.99 RVP in summer months. This reduces the number of blending components that a refiner may use to achieve compliance, placing upward pressure on prices for those components. It should also be stated that this requirement, while raising the price of gasoline, is done to lower the vaporizing point of gasoline in warmer summer months to prevent both air emissions related to vaporizing gasoline and vapor lock.

Like gasoline, diesel also shows seasonal variation, but not in the same pattern (**Figure 118**). For diesel, the same month-and-year time effects regression estimate shows that prices rise from January to May, setting a high of roughly $0.09 for the first half of the year. The seasonal adder (or the addition in pricing due to time of year) then increases quickly to April and May levels in August, with September being the most expensive margin month on average, before finishing the year at roughly a $0.07 average. In the case of diesel, the seasonal adders are significantly less than their gasoline counterparts. With diesel, seasonality explains at most roughly $0.10 of monthly change in diesel prices versus gasoline which seasonality can explain up to roughly $0.40. Given that the regression t-tests for the diesel monthly Boolean variables mostly show non-significance at 90 percent confidence levels, it is not unreasonable to assume the seasonality has no influence on diesel prices.

**Figure 118: Regression Estimated Monthly Price Differences from a Base Average Price in January, Monthly Data (2003–2016)**




Source: Energy Commission.

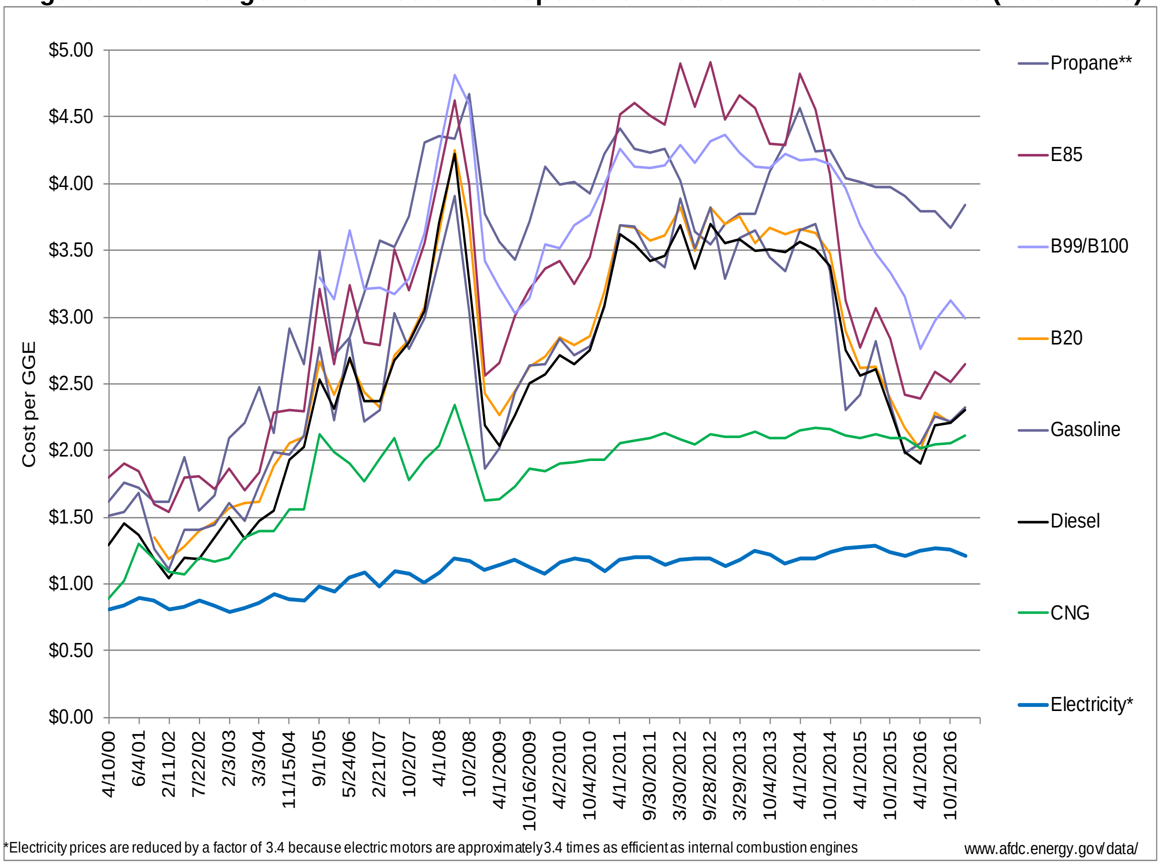
With regards to other transportation fuels dispensed in California, finding reliable California-specific information on the price levels of alternative fuels is difficult. **Figure 119** displays alternative transportation fuel prices as reported by the United States Department of Energy. These alternative transportation fuels include: Propane, E85, B99/B100, B20, CNG, and electricity.[157] Also displayed are the national average prices for both gasoline and diesel. Shown in this figure, prices of fuels such as E85, B99/B100, and B20 seem to show high levels of correlation to gasoline and diesel prices. At a retail level, this monthly pricing relationship makes economic sense, as these fuels can be viewed as direct substitutes for both gasoline and diesel. E85 is a substitute for gasoline in flexible-fuel vehicles, but offers fewer miles per physical gallon than gasoline. As for B20 and B99/B100, they are direct substitutes for petroleum diesel fuel. Diesel engine vehicle owners should consult their owner's manuals for information regarding the level of non-petroleum based diesel for which their vehicle is rated. Both CNG and electricity prices appear to be unaffected by the price of conventional transportation fuels.

Staff obtained California-specific prices that were used in the national chart **Figure 119** from the Department of Energy, but for a shorter period. **Figure 120** displays those prices. Trends seen in this chart are similar to those displayed in the national level chart, with propane appearing to be an exception. At the national level, the average difference between the regular gasoline price and gasoline gallon equivalent (GGE) price for propane from January 2010 to January 2017 was $0.97. In California, that same differential was $0.75. Most of the difference appears to be from GGE propane prices failing to fall along with drops in gasoline and crude oil prices at the end of 2014 and the start of 2015 on the national level. In California, propane prices did drop. It should

157 Electricity prices are reduced by a factor of 3.4 because electric motors are 3.4 times as efficient (on a BTU basis) as internal combustion engines. Efficiency adjustments were not made for other fuels because they are much smaller and inconsistent. Residential electricity prices were used because most recharging events occur at home. Propane prices reflect the weighted average of "primary" and "secondary" stations. EER is only applicable to light duty vehicles.

also be noted that the large increases in regular gasoline prices in February, May, and July of 2015 that were the subject of the Energy Commission's Petroleum Market Advisory Committee meetings do not show up in this information. This is likely due to the sampling methodology of the Department of Energy data, as they appear to only collect data for one month within a given quarter.

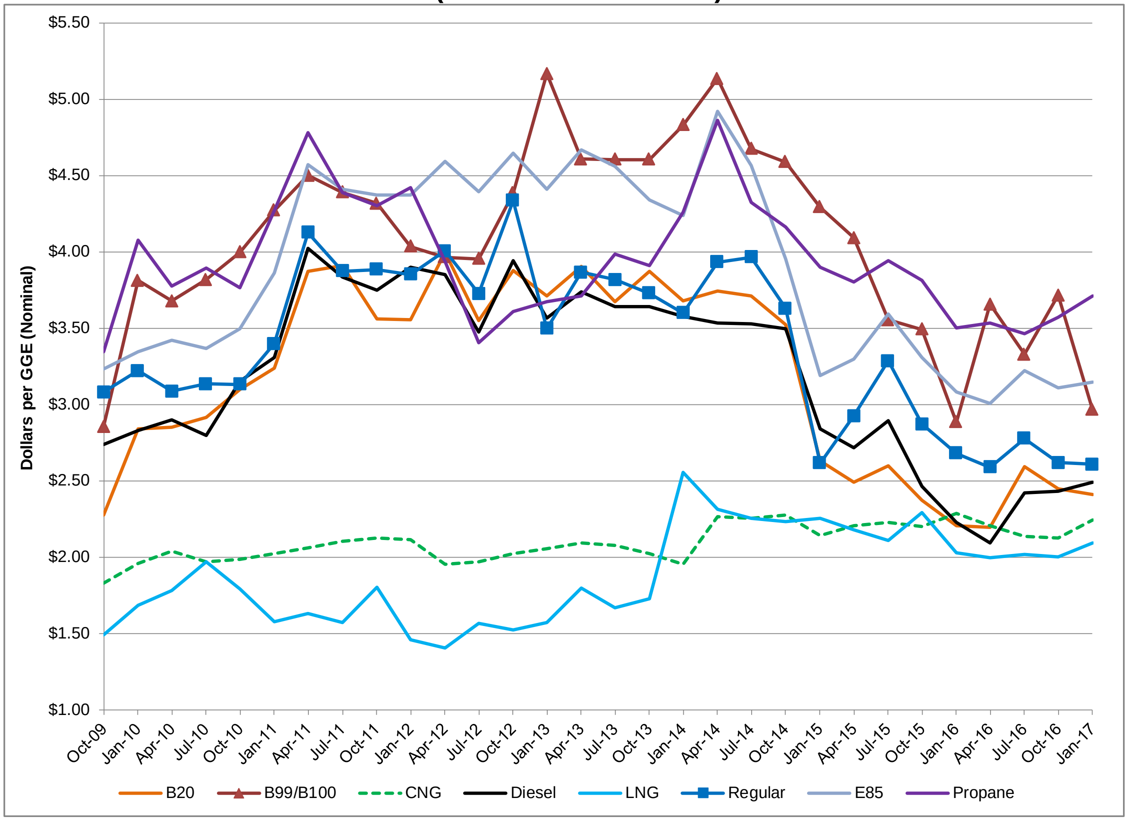
**Figure 119: Average Retail Price of Transportation Fuels in the United States (2000–2016)**




Source: Clean Cities Alternative Fuel Price Reports (www.afdc.energy.gov/data).

In both **Figure 119** and **Figure 120**, B20 diesel appears to be priced similarly to petroleum-based diesel, despite the fact that pure biodiesel blends of B99/100 averaged $0.63 more than diesel on a native (non-GGE) gallon-for-gallon basis. When the difference between B20 and petroleum-based diesel prices were averaged over the January 2010 to January 2017 time period, the average difference amounted to less than a tenth of a penny. This trend difference—combined with B20 being a perfect substitute for petroleum diesel, and B20 normally being the highest concentration of biodiesel in a diesel fuel that can be used in light- and heavy-duty vehicles—indicates that the petroleum-based diesel price will be representative of concentrations of biodiesel within the diesel pool, for price forecasting purposes.

**Figure 120: Average Retail Price of Transportation Fuels in California (Oct. 2009 to Jan 2017)**




Source: Clean Cities Alternative Fuel Price Reports ([www.afdc.energy.gov/data](www.afdc.energy.gov/data)) and Energy Commission.

CNG and electricity are the two transportation fuels with prices showing little correlation to petroleum prices in both **Figure 119** and **Figure 120**. In the case of transportation CNG the price has tracked local and national hub prices for natural gas with a relatively constant margin that accounts for compression and other costs. On a GGE basis, this margin is larger than the one seen in the gasoline and diesel market. However, this increased cost is understandable given that gasoline and diesel do not require compression before they are dispensed for retail purposes.

Electricity prices displayed in **Figure 119** are based on residential electricity rates per Department of Energy documentation. Department of Energy assumes that most charging of vehicles occurs at a residential rate. In California, there are several electricity charging rates that could be used to charge vehicles. Traditional residential rates are one method, typically involving tiered rates based on usage and independent of time of use. Other plans targeting electric vehicles also exist, such as Southern California Edison's Time-Of-Use Metering Rate-1 electric vehicle plan,[158] Pacific Gas and Electric's Residential Time-Of-Use Service for Plug-In Electric Vehicle plan,[159] and Los Angeles Department of Water and Power's Residential EV Charger Rebate

158 Southern California Edison Website: [https://www.sce.com/wps/portal/home/residential/electric-cars/residential-rates/](https://www.sce.com/wps/portal/home/residential/electric-cars/residential-rates/)

159 Pacific Gas and Electric website: [https://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_EV.pdf](https://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_EV.pdf)

Program.[160] At non-residential charging sites, the price of charging might include both the cost of utility-delivered electricity as well as the business profit margins of private charging networks. Full analysis has yet to be done on charging options and prices.

160 Los Angeles Department of Water and Power website: https://www.ladwp.com/ladwp/faces/ladwp/residential/r-gogreen/r-gg-driveelectric

# ACRONYMS/ABBREVIATIONS

| | |
|---|---|
| APNC | Approved Projects – Not started Construction |
| ASTM | American Society for Testing and Materials |
| B100 | Diesel fuel containing 100 percent biodiesel by volume |
| B20 | Diesel fuel containing 20 percent biodiesel by volume |
| B5 | Diesel fuel containing 5 percent biodiesel by volume |
| B99 | Diesel fuel containing 99 percent biodiesel by volume |
| BAAQMD | Bay Area Air Quality Management District |
| BOE | California State Board of Equalization |
| BPD | Barrels per day |
| CARB | California Air Resources Board |
| CARBOB | California Reformulated Blendstock for Oxygenate Blending |
| CBI | Caribbean Basin Initiative |
| CBR | Crude-by-Rail |
| CEC | California Energy Commission |
| CNG | Compressed natural gas |
| DOGGR | California Division of Oil, Gas and Geothermal Resources |
| E10 | A blended transportation fuel product that is 90 percent gasoline and 10 percent denatured ethanol by volume |
| E100 | A transportation fuel product that is 100 percent by volume denatured ethanol |
| E15 | A blended transportation fuel product that is 85 percent gasoline and 15 percent denatured ethanol by volume |
| E85 | A blended transportation fuel product that is 15 to 23 percent gasoline and 77 to 85 percent denatured ethanol by volume |
| EIA | Energy Information Administration |
| gCO2E/MJ | grams of carbon dioxide equivalent per megajoule |
| GHG | Greenhouse gas |
| GREET | Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model |
| GWh | Gigawatt hour |
| IEA | International Energy Agency |
| *IEPR* | *Integrated Energy Policy Report* |
| IMO | International Maritime Organization |
| LCFS | Low Carbon Fuel Standard |
| LNG | Liquefied natural gas |
| MOGAS | Motor Gasoline |
| MTBE | Methyl tertiary butyl ether |
| MWh | Megawatt hour |
| NACS | National Association of Convenience Stores |
| NYMEX | New York Mercantile Exchange |
| OECD | Organization for Economic Co-operation and Development |

| | |
|---|---|
| OPEC | Organization of Petroleum Exporting Countries |
| PADD | Petroleum Administration for Defense Districts |
| PBF | A joint venture of three companies: Petroplus Holdings, Blackstone Group and First Reserve |
| PIIRA | Petroleum Industry Information Reporting Act |
| PR | Permit Rescinded, see Appendix A |
| PR | Proposed Rule |
| RAC | Refiner acquisition cost |
| RBOB | Reformulated Blendstock for Oxygenate Blending |
| RFG | Reformulated gasoline |
| RFS | Renewable Fuel Standard |
| RFS2 | Revised Renewable Fuel Standards |
| RVP | Reid vapor pressure |
| SAV | Sacramento Valley Railroad |
| SCAQMD | South Coast Air Quality Management District |
| Secex | Secretariat of Foreign Trade in the Brazilian Ministério da Indústria, Comércio Exterior e Serviços, |
| Socal | Standard Oil Company of California |
| Socony | Standard Oil Company of New York |
| $SO_x$ | Oxides of sulfur |
| SP | Seeking permit |
| SWRCB | California State Water Resources Control Board |
| TAME | Tertiary amyl methyl ether |
| U.S. | United States |
| U.S. FHA | United States Federal Highway Administration |
| UCO | Used cooking oil |
| UNEV | Pipeline running between Las Vegas, Nevada and Salt Lake City, Utah |
| UNICA | União da Indústria de Cana-de-Açúcar', the Brazilian Sugarcane Industry Association |
| UP | Union Pacific railway |
| USA | United States of America |
| USD | U.S. Dollars |
| USDA | United States Department of Agriculture |
| USDG | United States Development Group |
| UST | Underground storage tank |
| VMT | Vehicle miles traveled |
| WA | Washington |
| WDGS | Wet distillers grains with solubles |
| WSDOT | Washington State Department of Transportation |
| WTI | West Texas Intermediate |

# APPENDIX A: West Coast Crude-by-Rail Projects Status

## California CBR Projects

As part of on-going work to monitor crude oil entering California, staff has tabulated a list of known CBR projects that can accept crude oil shipments into California. **Table A-1** lists California specific CBR facilities that are operational or planned.

**Table A-1: California Crude-by-Rail Projects**

| | **Proposed Facilities** | **Receipt Capability (BPD)** | **Status** |
|---|---|---|---|
| 1 | WesPac-Pittsburg | 50,000 | Permit abandoned late 2015 |
| 2 | Valero-Benicia (SP) | 70,000 | Permit denied September 20, 2016 |
| 3 | Phillips 66-Santa Maria (SP) | 37,000 | Permit denied by the County Planning Commission March 17, 2017; notice of Final County Action delivered to Phillips 66 |
| 4 | Alon-Bakersfield (APNC) | 150,000 | Permit issued September 9, 2014 – No construction initiated at this time |
| | | | |
| | **Operational Facilities** | **Receipt Capability (BPD)** | **Status** |
| 1 | SAV Patriot-Sacramento (PR) | 10,000 | Permit rescinded (PR) |
| 2 | KinderMorgan-Richmond | 16,000 | Permit rescinded |
| 3 | Kern Oil-Bakersfield | 26,000 | Operational |
| 4 | Plains-Bakersfield | 65,000 | Operational November 2014 |
| 5 | Tesoro-Carson | 3,000 | Operational |
| 6 | Alon-Long Beach | 10,000 | Operational |
| 7 | ExxonMobil-Vernon | 3,000 | Operational |
| | | | |
| | **Total California CBR Status** | **BPD** | |
| | Current receipt capability | 107,000 | |
| | Approved projects – not started construction (APNC) | 150,000 | |
| | Permit rescinded | 26,000 | |
| | Permit denied (PD) | 107,000 | |
| | No Longer Seeking Permit | 50,000 | |

Source: California Energy Commission analysis and research

## Northern California Facility Details

### WesPac Energy Project –Pittsburg, No Longer Seeking Permit

- Rail receipt average capability of 50,000 BPD
- Also plan marine terminal for receipt and loading – average of 192,000 BPD
- Combined average receipt capability of 242,000 BPD
- Connection to KLM pipeline – access to Valero, Shell, Tesoro, and Phillips 66 refineries
- Connection to idle San Pablo Bay Pipeline – access to Shell, Tesoro, and Phillips 66 refineries
- Project will require approval of the City of Pittsburg
- Construction could be completed within 18 to 24 months of receiving all permits
- Early 2015 - applicant modified project to exclude rail receipt capability
- July 2015 - Notice of Preparation of a Second Recirculated Draft EIR released

### Valero – Benicia Crude Oil By Rail Project, Permit Denied

Benicia refinery

- Up to 100 rail cars per day or 70,000 BPD
- Construction would take 6 months
- Project will require approval of the City of Benicia
- Draft EIR released June 10, 2014
- Permit approval denied by City of Benicia September 20, 2016

## Bakersfield Region Facility Details

### Alon Crude Flexibility Project, Permits Approved

- Alon – Bakersfield Refinery
- 2 unit trains per day - 104 rail cars per unit train
- 150,000 BPD offloading capacity
- Will be able to receive heavy crude oil
- Oil tankage connected to main crude oil trunk lines – transfer to other refineries in northern and Southern California
- Kern County Board of Supervisors approved permits for the project on September 9, 2014
- Construction estimated to take nine months to complete

### Plains All American – Bakersfield Crude Terminal, Operational

- Up to 65,000 BPD
- First deliveries during the end of November 2014

## Southern California Facility Details

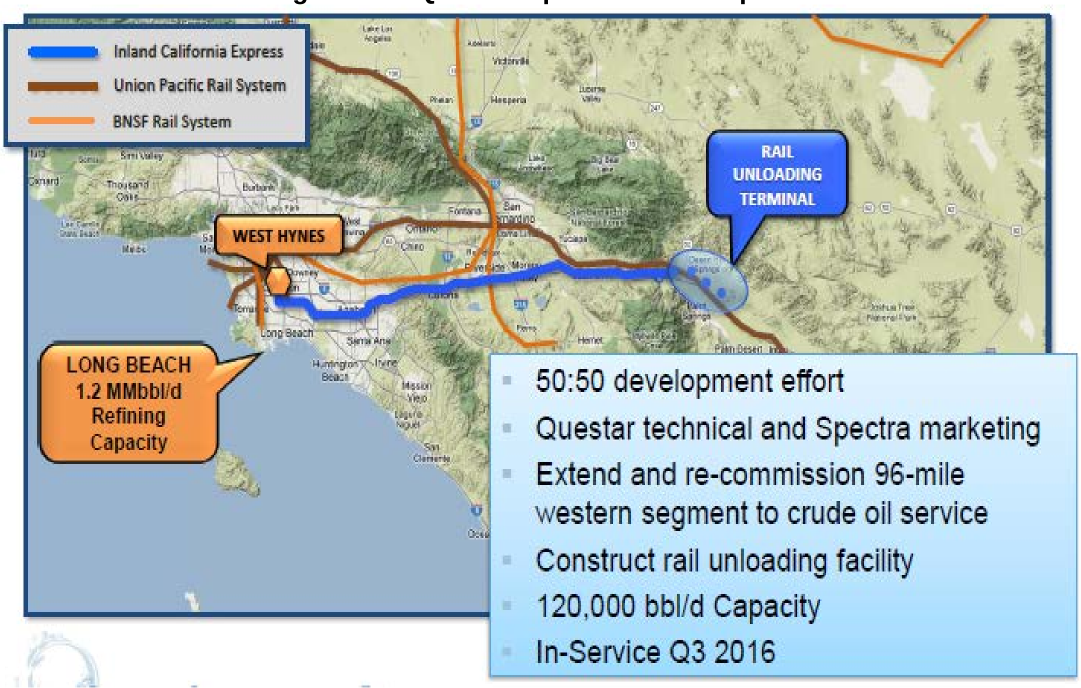
### Phillips 66 – Santa Maria Refinery, Permit Denied

- Up to 37,000 BPD
- Construction would require 9 to 12 months to complete
- Project will require approval of the San Luis Obispo County Planning Commission
- Revised Draft EIR to be re-circulated during October of 2014
- Project denied by the County Planning Commission on October 5, 2016
- Phillips 66 files appeal on October 19, 2016
- Board of Supervisors hearing held March 13, 2017
- Notice of Final County Action denying appeal sent to Phillips 66 on March 17, 2017

Besides the five previously described CBR California projects, the Energy Commission has monitored two other potential CBR projects, one in Stockton (Northern California) and another in Riverside County (Southern California). As of this writing, neither project is expected to be completed as planned.

The Targa project in the Port of Stockton is designed to receive CBR cargoes and transfer the oil to marine vessels for delivery to California refineries. The planned capacity of the facility is approximately 65,000 BPD. Another project is the Questar/Spectra CBR project, which is designed to import up to 120,000 BPD of crude oil to a yet-to-be-determined location in Riverside County that would then be off-loaded into storage tanks before being shipped via a combination of existing and new pipelines to refineries in Southern California (see **Figure A-1**).

**Figure A-1: Questar/Spectra CBR Proposal**

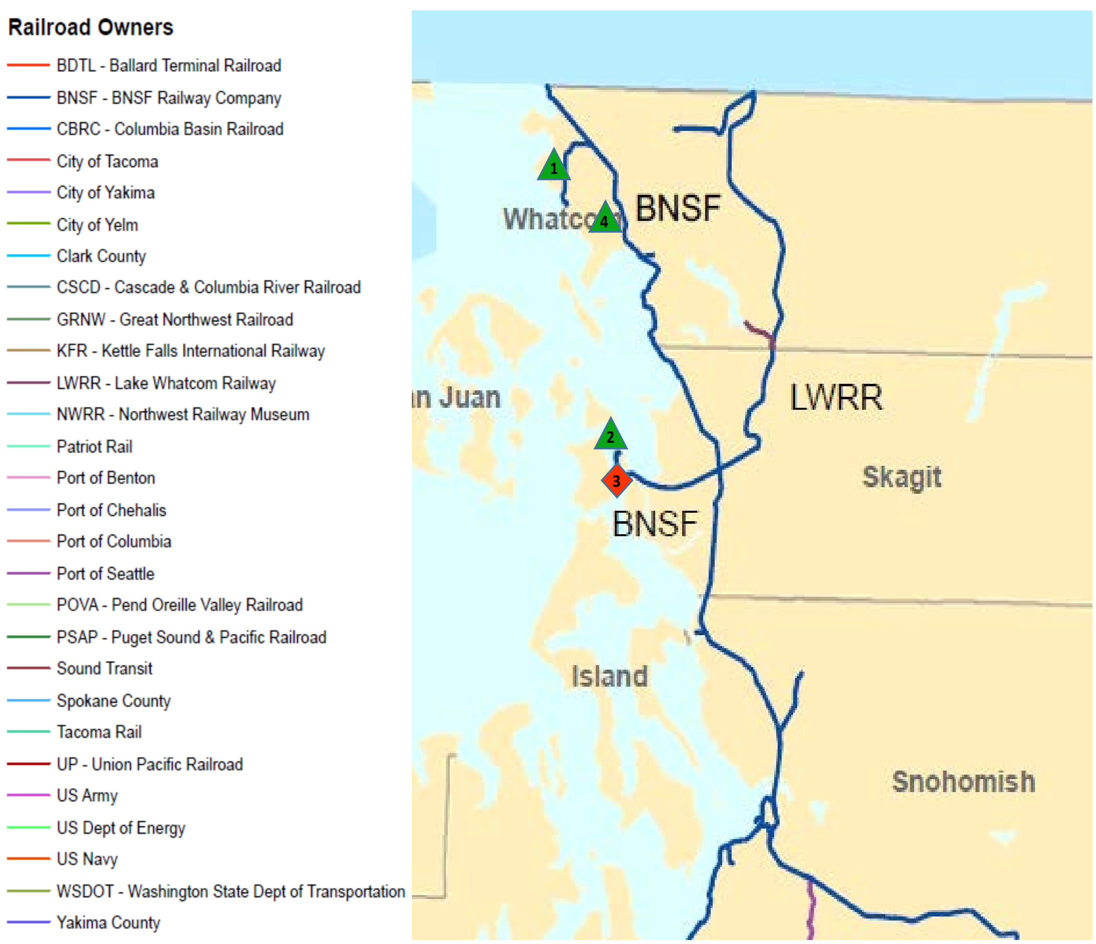



Source: Questar Pipeline customer meeting, March 2014.

## Pacific Northwest Crude-By-Rail Activity and Potential for Increased Imports

CBR projects were initiated earlier by refiners in Washington, since the rail transportation costs to bring crude oil to Washington was less than that to bring the oil to California. Washington refiners imported approximately 12.12 million barrels of crude oil via rail during 2012 and about 16.97 million barrels (roughly 46,500 BPD) during 2013. More recently, receiving terminals in the state are required to report rail deliveries by source, type, and route on a weekly basis. Based on this quarterly reporting, approximately 27.8 million barrels or 25 percent of the state's crude oil was imported via rail cars between October 1, 2016, and March 31, 2017. Washington refiners are also the biggest consumers of Alaska crude oil, which continues to decline in output, compelling refiners to seek alternative sources of crude oil to replace declining Alaska output. The light crude oil from Bakken (North Dakota) is similar in quality to Alaska crude oil, reducing the need to make additional refinery modifications to accommodate the new source of domestic crude oil. These Washington State CBR operational facilities, planned, and cancelled projects are listed in **Table A-2**. **Figures A-2** and **Figure A-3** display the locations of Pacific Northwest CBR facilities.

**Figure A-2: Northwest Washington CBR Facilities**



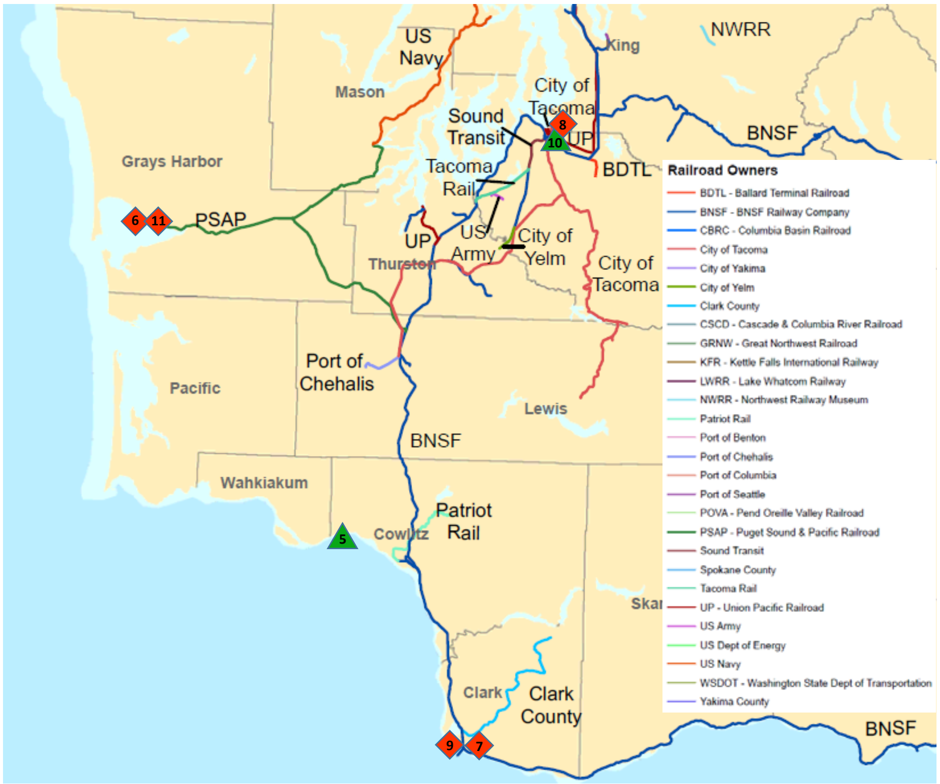

Source: WSDOT State Rail and Marine Office map and Energy Commission.

**Table A-2: Pacific Northwest Crude-by-Rail Projects**

| | Proposed Facilities | Receipt Capability (BPD) | Status |
|---|---|---|---|
| 1 | Tesoro-Savages – Vancouver, WA (SP) | 360,000 | EFSEC review extended to 6/30/17 |
| 2 | Westway Terminals – Grays Harbor (SP) | 49,000 | FEIS issued 9/30/16 |
| | | | |
| | **Operational Facilities** | **Receipt Capability (BPD)** | **Status** |
| 1 | BP – Cherry Point refinery | 60,000 | Operational December 2013 |
| 2 | Global Partners – Clatskanie, OR | 120,000 | Switched to ethanol 3rd Quarter 2016 |
| 3 | Phillips 66 – Ferndale refinery | 40,000 | Operational December 2014 |
| 4 | Tesoro – Anacortes refinery | 50,000 | Operational September 2012 |
| 5 | US Oil & Refining – Tacoma | 48,000 | Operational April 2013 |
| | | | |
| | **Canceled Projects** | **Receipt Capability (BPD)** | **Status** |
| 1 | Imperium Renewables – Grays Harbor (CP) | 78,000 | Cancelled project 11/30/15 |
| 2 | Nustar – Vancouver, WA (CP) | 23,000 | Cancelled project 3/30/17 |
| 3 | Shell – Anacortes refinery (CP) | 50,000 | Cancelled project 10/8/16 |
| 4 | Targa Sound – Tacoma (CP) | 41,000 | Cancelled project 9/6/13 |
| | | | |
| | **Total CBR Status** | **BPD** | |
| | Current receipt capability | 318,000 | |
| | Projects seeking permits (SP) | 409,000 | |
| | Cancelled projects (CP) | 192,000 | |

Source: California Energy Commission analysis and research

**Figure A-3: Southwest Washington and Northwest Oregon CBR Facilities**




Source: WSDOT State Rail and Marine Office map and Energy Commission.

## California and Washington Crude-By-Rail Routes

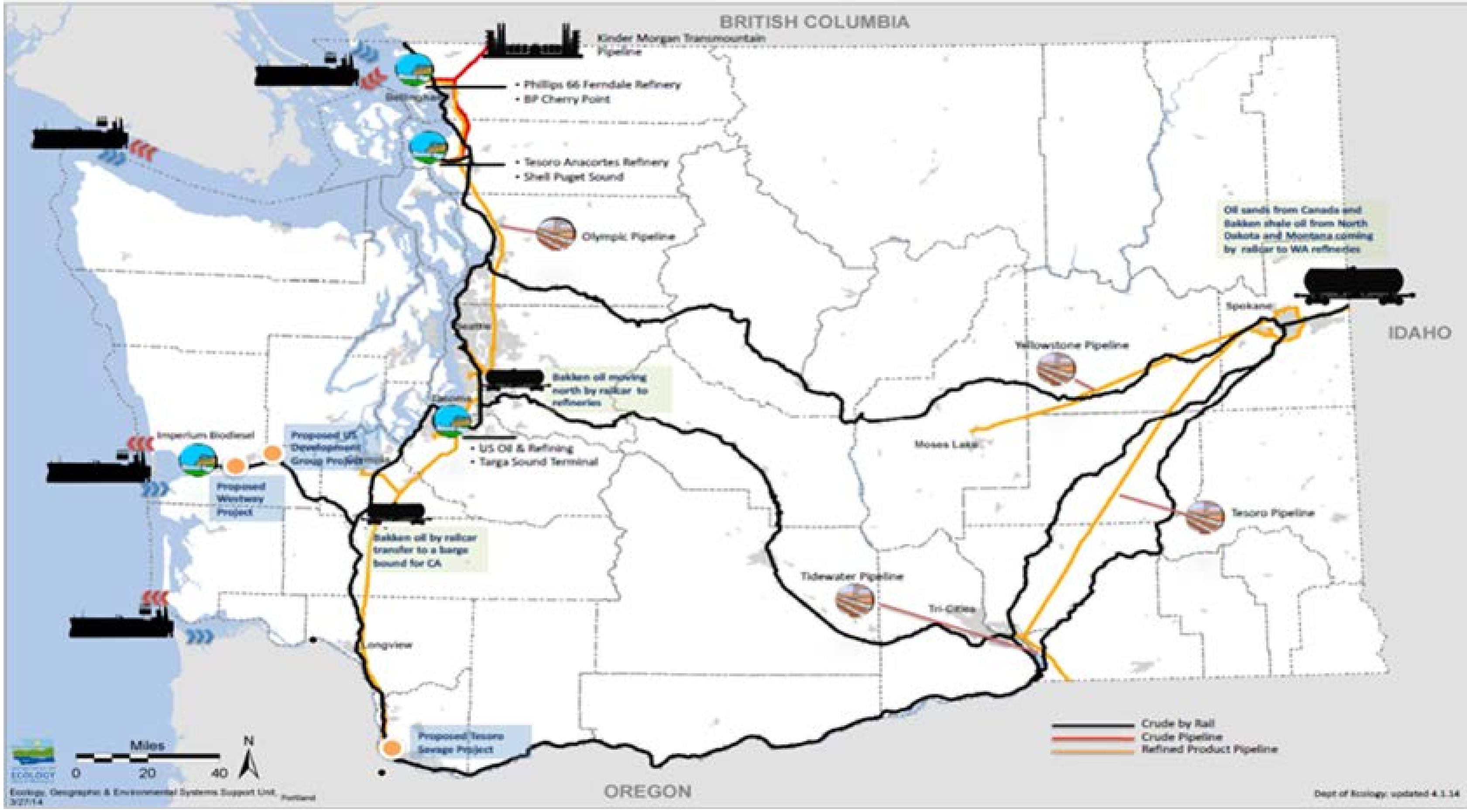
Union Pacific (UP) and Burlington Northern Santa Fe are the only two railroad companies that transport rail tank cars into California, utilizing portions of their own tracks or tracks owned by other companies. **Figure A-4** depicts the rail route options for these companies. The exact routes used by these companies to move rail tank cars containing crude oil into California is not precisely known since the rail companies have multiple routes to take, especially for CBR imports from Canada, North Dakota, Colorado, New Mexico, and Wyoming. It is likely that shipments of crude oil from Canada, North Dakota, and Wyoming initially enter California through southern Oregon and northwestern Nevada, while the balance of crude oil imports from other states initially enters California through western Arizona and southwestern Nevada. Although the volume of crude oil delivered by rail cars to each specific destination is collected from the rail companies and refiners through the Energy Commission's confidential PIIRA monthly data collection activity, the routing of these shipments is not required to be reported to the Energy Commission.

**Figure A-4: Rail Routes into and Within California**


Source: Figure 139 source: Department of Transportation

The likely route of CBR deliveries in Washington enters from western Idaho and traverses the state to reach off-loading facilities near the Puget Sound as illustrated in **Figure A-5** Canadian crude oil can also enter the state from British Columbia. Unlike the California CBR facilities under construction or planned, some of the proposed Washington facilities undergoing their respective permit approval processes are designed to load marine vessels for shipment to California refineries. All of the CBR projects in California are designed to be the final destination for the crude oil deliveries.

**Figure A-5: Rail Routes into and Within Washington**




Source: Washington Department of Ecology.