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ABSTRACT

For the *2009 Integrated Energy Policy Report*, California Energy Commission staff developed long-term forecasts of transportation fuel demand as well as projected ranges of transportation fuel and crude oil import requirements. These forecasts support analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, integration of energy use and land use planning, and transportation fuel infrastructure requirements. The projections and analysis indicate a potential need for targeted expansion of import infrastructure, particularly marine import facilities, to offset declining in-state oil production and growing demand in California, Nevada, and Arizona for transportation fuels. The magnitude of future contributions from efficiency improvements and various emerging transportation fuels and technologies is highly uncertain. Staff found that efficiency and emerging fuels and technologies can potentially displace significant amounts of petroleum, which will reduce the need for petroleum-specific infrastructure enhancements. However, many of these alternative fuels, in particular renewable fuels, may also require their own additional segregated import facilities, including pipelines and storage tanks. Moreover, developing the means of distributing these emerging alternative fuels, particularly through public retail refueling sites and home recharging systems, and aligning the development of these refueling systems with the rollout of appropriate numbers of vehicles may prove to be a challenge to industry and government.

KEYWORDS

California demand forecasts, transportation energy, gasoline, diesel, jet fuel, crude oil production, renewable fuels, alternative fuels, fuel imports, crude oil imports, marine import infrastructure, refining capacity, consumer preference, pipeline exports, retail refueling infrastructure, fuel prices.

EXECUTIVE SUMMARY

Background

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), requires the California Energy Commission to conduct "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices to develop policies for its *Integrated Energy Policy Report*." The Energy Commission develops long-term projections of California transportation energy demand that supports its analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, integration of energy use and land use planning, and transportation fuel infrastructure requirements.

This report summarizes the transportation energy demand forecasts, quantifies the petroleum and petroleum product-equivalent supply needs to meet the forecasted transportation energy demand, and identifies emerging constraints on transportation fuels infrastructure required to meet California's future transportation fuel demand. California's petroleum infrastructure is composed of the import and export system for petroleum, petroleum products, and renewable blendstocks; in-state refineries; and the distribution and storage network, made up of pipelines, trucks, rail, and storage tanks, that move petroleum, petroleum products, and renewable blendstocks to and from in-state refineries and to the refueling infrastructure. Increasingly, this transportation energy system will have to accommodate emerging renewable and alternative fuels that have their own sources of supply, as well as separate import, distribution, and retail refueling infrastructure.

While the Energy Commission expects consumption of transportation energy in California to increase in the future under a variety of fuel price and regulatory conditions, there are substantial uncertainties associated with the future contributions of various renewable and alternative transportation fuels and technologies. These emerging fuels can potentially displace significant amounts of petroleum, which can reduce the need for petroleum-specific infrastructure enhancements. However, each of these alternative fuels has its unique set of marketing, supply, infrastructure, and regulatory issues constraining market penetration. Moreover, developing the means of distributing these emerging fuels through public retail refueling sites and home recharging systems and aligning the development of these refueling systems with the rollout of appropriate numbers of vehicles may prove to be a challenge to industry and government.

Selected Findings

The following represent some of the more important findings from the supporting analyses. Chapter 1 provides a more comprehensive summary listing.

Petroleum Transportation Fuels Demand Trends and Forecasts

- California average daily gasoline demand for the first four months of 2009 is 2.1 percent lower compared to the same period in 2008, continuing a declining trend since 2004. Over the 12-month period from May 2008 through April 2009, gasoline demand is down 4.6 percent compared to the previous 12-month period.
- California average daily diesel fuel demand for the first three months of 2009 is 7.7 percent lower compared to the same period in 2008, continuing a declining trend since 2007. Over the 12-month period from April 2008 through March 2009, diesel fuel demand declined to 10.2 percent compared to the previous 12-month period.
- Between 2005 and 2007, California jet fuel demand rose 5 percent, but from 2007 to 2008 declined 8.9 percent.
- Between 2007 and 2030, staff estimates total annual gasoline consumption in California to fall 33.6 percent in the low-demand case to 10.25 billion gallons, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. This is a rather dramatic decline in gasoline consumption but roughly corresponds to levels of gasoline demand projected in the *State Alternative Fuels Plan* Moderate Case. In the high-demand case, the recovering economy and lower relative prices lead to a gasoline demand peak in 2016 of 15.25 billion gallons before consumption falls to a 2030 level of 13.87 billion gallons, 10.4 percent below 2007 levels.
- Between 2007 and 2030, staff expects total diesel demand in California to increase 7 percent in the low-demand case to 4.07 billion gallons and 16 percent in the high-demand case to 4.42 billion gallons.
- Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 51.2 percent to 5.12 billion gallons in the low demand case, and 67.2 percent to 5.75 billion gallons in the high-demand case.

Renewable and Alternative Fuels

Ethanol

- The federal Renewable Fuels Standards 2 will require more renewable fuels, primarily ethanol, and to a lesser extent biodiesel. Under the Low Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1.2 billion gallons in 2010 to 2.1 billion gallons by 2020. Under the High-Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1.2 billion gallons in 2010 to 2.6 billion gallons by 2020.

- It is estimated that ethanol demand in California will exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on the gasoline demand growth rates. However, it is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume (E10), even if the U.S. Environmental Protection Agency ultimately grants permission for United States refiners and marketers to go to E15.

- Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with the Renewable Fuels Standards 2 requirements. Assuming a 10 percent ethanol blend wall, E85 sales in California are forecast to rise from 2 million gallons in 2010 to 1,389 million gallons in 2020 and 1,678 million gallons by 2030 under the High Demand Case for gasoline. However, the pace of this expansion may still not be enough to achieve compliance due to a variety of infrastructure challenges and disincentives.

- Depending on the amount of fuel sold for a typical E85 dispenser, California would require between 3,000 and 19,000 E85 dispensers by 2020. To put that figure in perspective, there were approximately 42,000 total retail fuel dispensers in the entire state during 2008.

- What type of base gasoline will be necessary to blend with ethanol to produce E85? If the blendstock is something other than California reformulated blendstock for oxygenate blending (CARBOB) for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.

- California's number of registered flexible fuel vehicles must increase from a total of 382,000 vehicles in October 2008 to as many as 2.4 million flexible fuel vehicles by 2020 and 3.3 million by 2025 to help ensure that sufficient volumes of E85 can be sold to meet growing mandated ethanol blending requirements.

- The proposed Renewable Fuels Standards 2 regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to comply with the Renewable Fuels Standards 2 requirements, but retail station operators do not have any obligation. This is an apparent "disconnect" in the Renewable Fuels Standards 2 policy that could easily result in a retail infrastructure that is inadequate to handle the necessary increase in E85 sales.

- It is unlikely that there will be sufficient cellulosic ethanol capacity in place to meet the Renewable Fuels Standards 2 obligations in 2010. Therefore, U.S. Enviromental Protection Agency should delay the cellulosic obligations until such time that commercial production capacity is actually operational. Specifically, U.S. Environmental Protection Agency could set the national cellulosic ethanol use requirement for each

January 1, based on the level of commercial-scale nameplate capacity of operating facilities in North America as of the preceding July 1.

- The Low Carbon Fuel Standard will change the mix of ethanol types that will be used in California, namely ethanol from the Midwest will become more difficult to use, while ethanol from Brazil (sugar cane-based) will become increasingly attractive. Although the carbon intensity reductions of the Low Carbon Fuel Standard appear modest, the anticipated trend of shifting from one type of ethanol to others will create potential supply and logistical challenges that could be difficult to overcome and probably result in higher compliance costs that will be passed along to consumers.

- Blending ethanol in E85 (under most circumstances) can achieve full per-gallon compliance with the Low Carbon Fuel Standard without requiring any off-setting carbon credits. The only exceptions are California ethanol facilities that have dry distillers grain with solubles co-products and certain sources of Midwest ethanol.

- The Low Carbon Fuel Standard is expected to further complicate matters by pushing obligated parties to select types of ethanol that have lower carbon intensities, such as ethanol produced from sugarcane in Brazil. California's logistical infrastructure for the importation and re-distribution of ethanol will need to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months.

- California's ethanol import and redistribution infrastructure will need to change rather quickly to accommodate the anticipated transition to 10 percent (E10) blending beginning January 1, 2009. It is likely that an adequate infrastructure will be in place to increase ethanol blending by over 50 percent (compared to 2009 levels).

- If California were to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. Infrastructure projects to accommodate both means of receipt are being pursued but have yet to begin construction.

Biodiesel

- A growing percentage of total U.S. biodiesel supply has been exported, rather than used in domestic transportation fuels. Biodiesel exports have grown from nearly 9 million gallons in 2004 to over 677 million gallons in 2008 due to more attractive wholesale prices and U.S. exporters' use of the dollar per gallon biodiesel blenders' credit. In 2008 alone, export volumes represented 68 percent of total U.S. biodiesel supplies (production combined with imports).

- However, the continuous flow of biodiesel exports to Europe from the United States is not expected to be maintained since the European Union has recently taken action to apply a combination of import duties designed to compensate for the economic advantage gained by United States biodiesel exporters from the dollar per gallon blenders' credit.

- The Renewable Fuels Standards 2 regulations call for a minimum use of 1 billion gallons per year of biomass-based diesel fuel by 2012. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity, and another 289 million gallons per year capacity under construction. It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the Renewable Fuels Standards 2 requirements for several years.

- Under the Low Diesel Demand Case, biomass-based diesel "fair share" ("fair share refers to California's fair share of renewable fuel consumption under the Renewable Fuels Standards 2) ranges from 38 million gallons in 2010 to 57 million gallons by 2030. Under the High Diesel Demand Case – biodiesel "fair share" ranges from 37 million gallons in 2010 to 58 million gallons by 2030.

- Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), distribution terminal modifications could be undertaken and completed to enable an expansion of biodiesel use.

Other Alternative Fuels

- Natural gas has demonstrated a broad range of transportation applications, including light-, medium-, and heavy-duty uses in personal, transit, commercial, and freight roles, although overall numbers of vehicles are relatively small. The technology has also proven to have significant potential for carbon reduction, which can be further developed by advances in biogas technology.

- Lack of vehicle offerings, high vehicle cost and reduced range compared to gasoline vehicles, consumer unfamiliarity with the technology, and the need for investment in refueling infrastructure are among the more pressing impediments to developing transportation natural gas potential.

- Electric vehicle technology has the potential to significantly reduce carbon emissions and petroleum use. Fuel costs can also be considerably less than conventional petroleum fuels, taking into account the energy efficiency of the vehicle, especially given favorable rates for time of use metering and designated second meters.

- Consumer perceptions of electric vehicle technology vary widely. While full electric vehicles are not generally viewed favorably, compared to gasoline vehicles, plug-in hybrids appear to generate a much more positive impression.

- Battery costs outweigh all other incremental cost factors in the production of these vehicles and must be lowered to improve the commercial viability of the product. Increased reliance on lithium-ion battery technology will necessitate more rigorous assessment of the availability of lithium supply.

- Not enough information on consumer acceptance, vehicle availability, and infrastructure development is available to forecast future fuel cell vehicle purchases and hydrogen fuel use at this time. Fuel cell vehicles need to be brought out of the research and development stage to fully evaluate their commercial and environmental potential.
- A wide variety of methods and feedstocks can be used in the production of hydrogen fuel. GHG reduction factors are greatly influenced by the process used, but generally the carbon and petroleum reduction potential is very high.
- Standard measurements and fuel quality specifications need to be established to promote the sale of hydrogen as a transportation fuel.

Crude Oil Import Forecast

- California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than any point since 1985. Since 1986, California crude oil production has declined by 41.4 percent; Alaska, by 63.2 percent; and the rest of the United States, by 36.3 percent. Over the last 10 years, California's crude oil production has declined at an average rate of 3.2 percent per year. Between 2006 and 2008, the decline rate is lower, averaging 2.2 percent per year.
- In 2008, California refiners imported 406 million barrels of crude oil. Crude oil imports are continuing to increase throughout the forecast period, requiring an expansion of the existing crude oil import infrastructure to ensure a continued adequate supply of feedstock to enable refiners to operate their facilities at levels sufficient to supply California and the neighboring states with projected quantities of transportation fuels to meet forecasted demand.
- Under the Low Case projection, annual crude oil imports are forecast to increase by 34 million barrels between 2008 and 2015 (8.5 percent increase), by 55 million barrels by 2020 (13.6 percent increase), and by 91 million barrels by 2030 (22.5 percent increase compared to 2008).
- Under the High Case projection, annual crude oil imports rise by 70 million barrels between 2008 and 2015 (17.3 percent increase), by 113 million barrels by 2020 (28 percent increase) and by 190 million barrels by 2030 (47 percent increase compared to 2008).
- Southern California will require an expansion of the existing crude oil import infrastructure to avoid detrimental impact on refinery operations. Although progress continues in developing Berth 408 in the Port of Los Angeles, the time required to obtain all of the necessary permits to begin construction is now more than four years. In fact, Plains All-American, a company engaged in the transportation, storage, terminalling and marketing of crude oil and refined products, still does not have all of the requisite approvals necessary for them to initiate construction.

- Additional storage tank capacity would have to be constructed to handle the incremental imports of crude oil, between 1.5 and 5.8 million barrels by 2015; between 2.4 and 9.5 million barrels by 2020; and between 4.0 and 15.9 million barrels of storage capacity by 2030.
- The continued decline of California's crude oil production could be reversed through increased exploration and drilling in state and federal waters, but any appreciable impact on the level of imported oil would be at least a decade away. If the lifting of the moratoria on Outer Continental Shelf drilling off the coast of California remains and expanded exploration and development is allowed to proceed, crude oil production off the coast could increase from 110,000 barrels per day in 2008 to approximately 310,000 barrels per day by 2020 and 480,000 barrels per day by 2030.

Petroleum Product Import Forecast

- Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. In 2006, approximately 55 percent of Arizona's demand was met by products exported from California. However, that percentage dropped to just 35 percent by 2008 as refiners and other marketers shifted source of supply from California and Texas and New Mexico.
- Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account East Line expansion plans, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market.
- The continued growth of transportation fuel demand in Arizona and Nevada could eclipse the capacity of some portions of the Kinder Morgan pipeline distribution system during the forecast period, absent additional expansions. Most segments are not expected to exceed maximum pumping capacity over the forecast period due to the recent, significant drop in transportation fuel demand and lower demand outlooks linked to increased use of renewable fuels and improved fuel economy standards for motor vehicles.
- Under the High Import Case analysis, California imports of gasoline are forecast to decrease significantly over the next 15 years, while imports of diesel and jet fuel would still rise to keep pace with growing demand for those products. Under the Low Import Case scenario, the growing imbalances between gasoline and the other transportation fuels are even more extreme, resulting in a net decline of imports of at least a 250,000 barrels per day by 2015. This latter type of outcome is unlikely to materialize as refiners will adjust operations to decrease the ratio of gasoline components that are produced for each barrel of crude oil processed.

CHAPTER 1: Introduction To Transportation Energy Forecasts

Transportation Energy Analyses

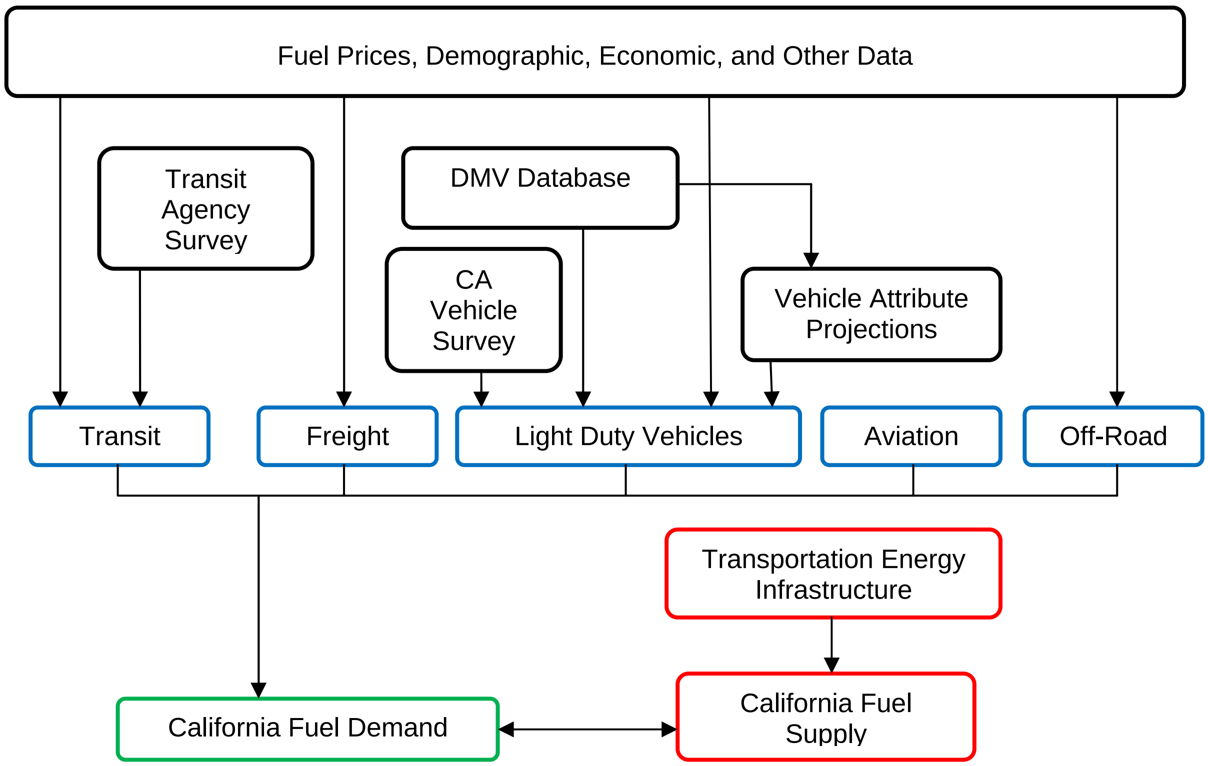
As required by SB 1389, the California Energy Commission conducts “assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices.” The Energy Commission reports these assessments and forecasts in its *Integrated Energy Policy Report* (*IEPR*), which it adopts every odd-numbered year (Public Resources Code [PRC] §25302[d]).

Transportation energy demand and fuel price forecasts support several state energy policy and program activities, including the alternative vehicle and fuel technology analysis mandated by Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005); petroleum use reduction and efficiency assessments; land use planning analysis; and transportation energy infrastructure requirements assessment. Since the *2007 IEPR*, Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008); has been signed into law, the Low Carbon Fuel Standards (LCFS) have been adopted by the California Air Resources Board (ARB), and the 2009 American Recovery ans Reinvestment Act (ARRA) was enacted which included multiple elements to advance energy efficiency and alternative fuel and vehicle technologies. SB 375 links greenhouse gas (GHG) reductions with transportation funding, land use planning, and housing policy, which in turn requires more integration of land use and transportation models. The LCFS sets carbon reduction standards that will affect the types of fuels that can be sold in California, particularly renewable fuels. The federal stimulus bill has increased the incentives available to higher efficiency and alternative fuel technologies.

While the Energy Commission expects consumption of transportation energy in California to increase in the future under a variety of fuel price and regulatory conditions, there are substantial uncertainties associated with the future contributions of various renewable and alternative transportation fuels and technologies. These emerging fuels can potentially displace significant amounts of petroleum, which can reduce the need for petroleum-specific infrastructure enhancements. However, each of these alternative fuels has its own unique set of supply, infrastructure, and regulatory issues constraining market penetration. Moreover, developing the means of distributing these emerging fuels through public retail refueling sites and home recharging systems and aligning the development of these refueling systems with the rollout of appropriate numbers of vehicles may prove to be a challenge to industry and government. These issues will be discussed in Chapter 3.

This staff draft report provides preliminary transportation energy analyses for the *2009 IEPR* with a focus on the implications of future transportation energy demand for California’s existing transportation fuels marine import facilities, as well as the state’s retail refueling infrastructure. Available time and resources dictate that staff focuses on those issues that appear to have the most pressing near-term consequences, namely the intersection of complex state and federal renewable fuel rules that prescribe percentages and volumes of renewable fuels consumed, particularly ethanol. Staff has attempted to incorporate additional alternative fuel vehicles and technologies, as compared with the staff report for the *2007 IEPR*,[1] but technical and data constraints have limited the quantitative analysis for this draft report.

Figure 2.1: Transportation Energy Data Flow Diagram



Summary of Staff Findings

The outlook for the adequacy of California's petroleum transportation fuel import infrastructure has improved slightly since publication of the *2007 IEPR*. This has occurred because of lower expectations of demand for these fuels due to general economic factors, higher fuel prices, and policies intended to reduce petroleum consumption. At the same time, other issues have risen with respect to meeting new state and federal low carbon and renewable fuel standards, as well as the sufficiency of supply and adequacy of import and distribution infrastructure for renewable and alternative fuels.

Numerous uncertainties can affect these estimates of future import and distribution infrastructure needs, including changes in fuel prices, rates of adoption of new technologies and alternative fuels, demand for fuels in California and neighboring states, decline rates of oil production in California, refinery and other infrastructure capacity expansions, and GHG reduction rules and standards. Moreover, as with all technical analysis, uncertainties will also be introduced with the use of forecasting models and other analytical tools, including the use of surveys and other data sources to calibrate and estimate models and the use of forecasts of input variables by other organizations. However, potential supply and capacity shortfalls lead staff to conclude that specific kinds of import and refueling infrastructure capacity expansions may need to occur to prevent economic losses to state consumers.

Staff has generated two crude oil price scenarios, representing plausible and sustainable long-term low and high crude oil prices. Each of these two crude price paths is also associated with a low and high price band for ethanol, natural gas, and electricity, generating four fuel price cases from the possible combinations. From these cases, the highest and lowest petroleum demand cases were analyzed for their compliance with existing low carbon and renewable fuels standards and impacts on import and distribution infrastructure. In the summary findings below, the highest and lowest expected demand levels for the petroleum fuels are reported as a range. On the supply side, staff developed high and low cases of crude oil and fuel import requirements that vary according to assumptions about crude oil production, refinery and pipeline expansion projects, port and marine terminal capacities, and California and neighboring state fuel demand. Staff also identified and attempted to quantify other factors that will affect the forecast of imports requirements. Findings that result from the development of these forecasts and analyses include the following:

Trends in Transportation

- Between 2009 and 2030, population is forecast to increase at an annual compound average rate of 1.1 percent, compared with a growth rate of 2.9 percent in real personal income over the same period. These rates of growth will result in substantial increases in travel demand for California.

- While projected population growth to 2030 has remained the same between the 2007 and 2009 forecasts, non-farm employment projections have been lowered in the 2009 forecast, resulting in a sharp decline in the percentage of California population employed.

- Between 2001 and 2008 the number of all alternative fueled vehicle types has increased in the state at rates substantially greater than for gasoline vehicles. This growth is particularly pronounced for hybrid electric vehicles at 75 percent over this period.

- Between 2004 and 2008 the percentage of new light-duty vehicle sales that were small and large cars grew significantly, with corresponding decreases in the shares of trucks and sport utility vehicles.

- The 2008 CVS verifies the significant impact of distance to work and availability of transit on vehicle miles traveled. Therefore, changes in land use patterns that reduce the distance between locations of job and residence, and increase the availability of urban transit, will reduce vehicle miles traveled and transportation fuel consumption per capita. Fuel costs have a significant influence on both vehicle choice and vehicle miles traveled.

- Between 2000 and 2008, the percentage of medium- and heavy-duty vehicles fueled by gasoline has fallen from 52 percent to less than 39 percent, with most of their share being taken over by diesel vehicles. Among alternative fuels, natural gas vehicles have built the largest share at slightly over 1 percent.

- Substantial growth in import container traffic at California ports has been an important factor in freight transportation energy use since 2000. However, the economic downturn has caused a decline of 20.3 percent in container traffic in 2008 compared to 2007.

- Data through the week ending August 1, 2009, show that rail carload activity is down 19 percent compared to the same period in 2008. Intermodal rail activity is also down 17.2 percent compared to last year, while estimated ton-miles of rail activity declined 18.1 percent compared to 2008. Domestic trucking activity is down 13.6 percent in June 2009 when compared to June 2008.

- California average daily gasoline demand for the first four months of 2009 is 2.1 percent lower compared to the same period in 2008, continuing a declining trend since 2004. Over the 12 month period of May 2008 through April 2009, gasoline demand is down 4.6 percent compared to the previous 12-month period.

- California average daily diesel fuel demand for the first three months of 2009 is 7.7 percent lower compared to the same period in 2008, continuing a declining trend since 2007. Over the 12-month period of April 2008 through March 2009, diesel fuel demand is down 10.2 percent compared to the previous 12-month period.

- Between 2005 and 2007, California jet fuel demand rose 5 percent, but from 2007 to 2008 declined 8.9 percent.

- Among 45 California transit agencies for which data was available from the American Public Transportation Association (APTA), ridership increased by 2.2 percent, to 1.34 billion trips, between 2007 and 2008.

Petroleum Transportation Fuel Demand Forecasts

- Between 2007 and 2030, staff expects total annual gasoline consumption in California to fall 33.6 percent in the low demand case to 10.25 billion gallons, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. This is a rather dramatic decline in gasoline consumption but roughly corresponds to levels of gasoline demand projected in the *State Alternative Fuels Plan* Moderate Case. In the high demand case, the recovering economy and lower relative prices lead to a gasoline demand peak in 2016 of 15.25 billion gallons before falling to a 2030 level of 13.87 billion gallons, 10.4 percent below 2007 levels.

- Between 2007 and 2030, staff expects total diesel demand in California to increase 7 percent in the low demand case to 4.07 billion gallons and 16 percent in the high demand case to 4.42 billion gallons.

- Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 51.2 percent to 5.12 billion gallons in the low demand case, and 67.2 percent to 5.75 billion gallons in the high demand case.

Renewable and Alternative Fuels

Ethanol

- Renewable Fuels Standards 2 (RFS2) will require greater use of renewable fuels, primarily ethanol and, to a lesser extent, biodiesel.
- Under the Low Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,208 million gallons in 2010 to 2,108 million gallons by 2020.
- Under the High Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,245 million gallons in 2010 to 2,550 million gallons by 2020.
- It is estimated that ethanol demand in California will eclipse an average of 10 percent by volume in all gasoline sales by between 2012 and 2013, depending on the gasoline demand growth rates.
- It is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume (E10), even if the United States Environmental Protection Agency (U.S. EPA) ultimately grants permission for United States refiners and marketers to go to E15.
- Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with RFS2 requirements. Assuming a maximum 10 percent ethanol content in gasoline, E85 sales in California are forecast to rise from 2 million gallons in 2010 to 1,389 million gallons in 2020 and 1,678 million gallons by 2030 under the High Demand Case for gasoline. However, the pace of this expansion may be inadequate to achieve compliance due to a variety of infrastructure challenges and disincentives.
- Depending on the amount of fuel sold for a typical E85 dispenser, California would require between 3,000 and 19,000 E85 dispensers by 2020. To put that figure in perspective, there were approximately 42,000 total retail fuel dispensers in the entire state during 2008.
- What type of base gasoline will be necessary to blend with ethanol to produce E85? If the blendstock is something other than California Reformulated Blendstock for Oxygenate Blending (CARBOB) for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.
- California's number of registered flexible fuel vehicles (FFVs) will need to increase from a total of 382,000 vehicles in October 2008 to as many as 2.4 million FFVs by 2020 and 3.3

million by 2025 to help ensure that sufficient volumes of E85 can be sold to meet growing mandated ethanol blending requirements.

- The proposed RFS2 regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to comply with the RFS2 standards, but retail station operators do not have any obligation. This is an apparent "disconnect" in the RFS2 policy that could easily result in a retail infrastructure that is inadequate to handle the necessary increase in E85 sales.

- E85 retail infrastructure is expensive. Costs for installing a new underground storage tank (UST), dispenser, and appurtenances range between $50,000 and $200,000. This level of investment is between 1.5 and 6 times greater than the total annual profit of a typical retail station (for both fuel and non-fuel commodities).

- Regulations adopted by ARB designed to reduce emissions from new vehicle models (both tailpipe and evaporative), along with revised zero emission vehicle (ZEV) standards will require automobile manufacturer compliance with more stringent emission standards and growing percentage of ZEV and partial zero emission vehicle (PZEV) sales. Both of these sets of standards will create significant challenges for greater introduction of FFVs.

- It is possible that vehicle manufacturer marketing decisions might preclude FFVs, setting the stage for a potential shortfall of new FFV vehicle availability in California in sufficient numbers to help meet compliance with the RFS2 renewable fuel obligations.

- Ethanol producers prefer to sell into the low-blend market of E6 or E10 due to higher likelihood of receiving near-gasoline prices. The E85 market is a less desirable outlet for their ethanol production, hence the reason ethanol producers support raising the ethanol "blend wall" from E10 to E15.

- Due to the lower energy content of a gallon of E85 versus a gallon of E10 (approximately 22 to 28 percent), ethanol suppliers and retailers will likely need to sell their product at a discount to achieve necessary sales volumes. This market differentiation will exacerbate current poor ethanol production economics.

- Renewable Identification Number (RIN) credit levels may not be sufficient to overcome the economic value of the fuel economy differential, even if one assumes that the blenders receiving the RIN credit revenue will be willing to pass some of that money back through to ethanol producers in the form of higher wholesale ethanol prices.

- As California sales of E85 increase, there should be steps taken to help ensure that FFV motorists are receiving adequate pricing information at retail stations to put them in a position of making more informed fuel purchase decisions. An example of increased consumer information would be an expansion of the California Division of Measurement Standards (DMS) posted retail price standards to include some form of energy-equivalent or fuel economy-equivalent pricing information at all retail stations offering E85 in California.

- LCFS will change the mix of ethanol types that will be used in California, namely corn-based ethanol from the Midwest will become increasingly difficult to use, while ethanol from Brazil (sugar cane-based) will become increasingly attractive.
- Although the carbon intensity reductions of the LCFS appear modest, the anticipated trend of shifting from one type of ethanol to others will create potential supply and logistical challenges that could be difficult to overcome and probably result in higher compliance costs that will be passed along to consumers.
- Brazilian ethanol may be blended in E10 for several years (up through 2016) without carbon credit offsets. California ethanol is viable in E10 blends for up to four years before it would need to be exported for use outside California or blended as E85. Finally, Midwest ethanol blending would be most limited, only able to be blended for a couple of years assuming the ethanol plant had wet distillers grain with solubles (DGS) as a co-product.
- Blending ethanol in E85 (under most circumstances) can achieve full per-gallon compliance with the LCFS without the need for any offsetting carbon credits. The only exceptions are California ethanol facilities that have dry DGS co-products and certain sources of Midwest ethanol.
- Additional pathways with lower carbon intensities (CI) can extend the length that ethanol can be used in gasoline blends for either E10 or E85. Verification of lower CI pathways is expected to continue over the next couple of years. This is especially the case once cellulosic ethanol and diesel fuel production is achieved and verified on a commercial scale.
- As of June 2009 there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States. Production capacity of conventional ethanol is expected to be adequate over the next several years as facilities resume operations and new producers come on-line after completing their construction projects.
- It is unlikely that there will be sufficient cellulosic ethanol capacity in place to meet the RFS2 obligations in 2010. Therefore, the U.S. EPA should delay the cellulosic obligations until such time that commercial production capacity is actually operational. Specifically, the U.S. EPA could set the national cellulosic ethanol use requirement for each January 1, based on the level of commercial-scale nameplate capacity of operating facilities in North America as of the preceding July 1.
- Currently, five of the six California ethanol facilities are idle with a collective production capacity of nearly 240 million gallons per year. These facilities are expected to resume operations sometime during 2010, if not earlier.

- Production of ethanol in Brazil is primarily determined by interrelationship between sugar market values and local renewable transportation demand. There may or may not be ample excess supplies of ethanol available to export from Brazil any given year.
- Brazilian exporters of ethanol to the United States must pay two types of import tariffs that total nearly 60 cents per gallon. Removing the tariff could reduce the price of ethanol in the United States by 2.5 to 14 percent, a potential benefit to consumers.
- The amount of excess ethanol that may be available to import from Brazil over the next several years is forecast to grow to between 1.9 and 3.2 billion gallons by 2015.
- Market price for Brazil ethanol imports is expected to command a premium to California-sourced ethanol, which should be more valuable than conventional corn-based ethanol produced outside the state. The anticipated higher, yet unknown, prices are assumed to be passed along to consumers.
- The LCFS is expected to further complicate matters by pushing obligated parties to select types of ethanol that have lower carbon intensities, such as ethanol produced from sugar cane in Brazil. California's logistical infrastructure for the importation and re-distribution of ethanol will need to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months.
- Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest.
- California's ethanol import and redistribution infrastructure will need to change rather quickly to accommodate the anticipated transition from E6 to E10 blending beginning January 1, 2010. It is likely that an adequate infrastructure will be in place to increase ethanol blending by more than 50 percent (compared to 2009 levels).
- If California were to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil; and rail shipments from another marine terminal outside California. Infrastructure projects to accommodate both means of receipt are being pursued but have yet to begin construction.

Agriculture

- As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. The portion of corn required to produce ethanol has been increasing at an accelerated pace and accounted for approximately 32.3 percent of domestic corn use in 2008.
- However, near-continuous yield improvement (as measured in bushels harvested per acre) through improved agricultural practices have enabled greater production of corn without any significant expansion of the number of acres planted.

- Corn yields are forecast to rise from 153.8 bushels per acre harvested in 2008 to 175.0 bushels per acre by 2018, an increase of 13.8 percent. According to the United States Department of Agriculture (USDA), the quantity of corn for production of fuel ethanol is forecast at 4.825 billion bushels for market year 2015/16, compared to 3.27 billion bushels in 2008.

Biodiesel

- Biodiesel exports have grown from nearly 9 million gallons in 2004 to over 677 million gallons in 2008 due to more attractive wholesale prices and U.S. exporters' use of the dollar per gallon biodiesel blenders' credit.

- A growing percentage of total U.S. biodiesel supply has been exported, rather than used in domestic transportation fuels. In 2008 alone, export volumes represented 68 percent of total United States biodiesel supplies (production combined with imports).

- However, the continuous flow of biodiesel exports to Europe from the United States is not expected to be maintained since the European Union has recently taken action to apply a combination of import duties designed to compensate for the economic advantage gained by U.S. biodiesel exporters from the dollar per gallon blenders' credit.

- Absent the large increase of biodiesel exports, blending levels in the United States could have increased to an average of 1.29 percent during 2008, rather than the actual 2008 average of 0.61 percent.

- Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations.

- There has been no quantitative analysis performed to determine how the volumes and types of biodiesel used in California could change as a consequence of the LCFS. When additional carbon intensity pathways for various types of biodiesel are published, the Energy Commission will conduct additional analysis to identify any potential supply or infrastructure issues that could result over the near to mid-term period.

- Under the Low Diesel Demand Case – biodiesel "fair share" ranges from 38 million gallons in 2010 to 57 million gallons by 2030. Under the High Diesel Demand Case – biodiesel "fair share" ranges from 37 million gallons in 2010 to 58 million gallons by 2030.

- The RFS2 regulations call for a minimum use of 1 billion gallons per year of biomass-based diesel fuel by 2012. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity, and another 289 million gallons per year capacity under construction. It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the RFS2 requirements for several years.

- The biodiesel infrastructure in California has not been developed to the same extent as that of ethanol primarily because there has not been any meaningful increase in the use of biodiesel to date.
- Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use.
- Distribution terminal modifications will need to be made over the near to mid-term to help ensure sufficient volumes of biodiesel will be available for blending with conventional diesel fuel.

Natural Gas

- Natural gas has demonstrated a broad range of transportation applications, including light-, medium-, and heavy-duty uses in personal, transit, commercial, and freight roles, although overall numbers of vehicles are relatively small. The technology has also proven to have significant potential for carbon reduction, which can be further developed by advances in biogas technology.
- Lack of vehicle offerings, high vehicle cost and reduced range compared to gasoline vehicles, consumer unfamiliarity with the technology, and the need for investment in refueling infrastructure are among the more pressing impediments to developing transportation natural gas potential.
- Current public refueling infrastructure varies widely by region. Initially, infrastructure development should be matched geographically with locations of greatest vehicle density.
- Developments that could stimulate transportation natural gas uses include new utility rate structures for home refueling, improved on-board storage technology, new hybrid natural gas technology, and use of carbon credits in investment plans.
- Impacts on the natural gas supply system of increased transportation consumption, as well as other potential competing uses, will need to be more carefully evaluated.

Electricity

- Electric vehicle technology has the potential to significantly reduce carbon emissions and petroleum use. Fuel costs can also be considerably less than conventional petroleum fuels, taking into account the energy efficiency of the vehicle, especially given favorable rates for time of use metering and designated second meters.
- Consumer perceptions of electric vehicle technology vary widely. While full electric vehicles (FEVs) are not generally viewed favorably, plug-in hybrids appear to generate a much more positive impression, compared to gasoline vehicles.

- Much more effort should be focused on development of residential refueling infrastructure. Standardized methods and equipment for the powering of these FEVs and plug-in hybrid electric vehicles (PHEVs) need to be established and training for technicians in installation and servicing needs to be more widely available.
- Battery costs outweigh all other incremental cost factors in the production of these vehicles and must be lowered to improve the commercial viability of the product. Increased reliance on lithium-ion battery technology will necessitate more rigorous assessment of the availability of lithium supply.
- Impacts on the electricity supply system of widespread adoption of electric transportation technology will also need to be more carefully evaluated.

Hydrogen

- Not enough information on consumer acceptance, vehicle availability, and infrastructure development is available to forecast future fuel cell vehicle purchases and hydrogen fuel use at this time. Fuel cell vehicles need to be brought out of the research and development stage to fully evaluate their commercial and environmental potential.
- A wide variety of methods and feedstocks can be used in the production of hydrogen fuel. GHG reduction factors are greatly influenced by the process used, but generally the carbon and petroleum reduction potential is very high.
- Standard measurements and fuel quality specifications need to be established to promote the sale of hydrogen as a transportation fuel.

Crude Oil Import Forecast

- California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than any point since 1985. Since 1986, California crude oil production has declined by 41.4 percent; Alaska, by 63.2 percent; and the rest of the United States, by 36.3 percent. Over the last 10 years, California's crude oil production has declined at an average rate of 3.2 percent per year. Between 2006 and 2008, the decline rate is lower, averaging 2.2 percent per year.
- Between 2001 and 2008, California refinery creep (the gradual growth of California refinery capacity to process crude oil) for crude oil distillation capacity increased at an average rate of 0.84 percent per year. Between 2003 and 2008, the refinery creep rate was a little more than half that level at 0.45 percent per year.
- In 2008, California refiners imported 406 million barrels of crude oil. Crude oil imports are continuing to increase throughout the forecast period, necessitating an expansion of the existing crude oil import infrastructure to ensure a continued adequate supply of feedstock to enable refiners to operate their facilities at levels sufficient to supply California and the neighboring states with projected quantities of transportation fuels to meet forecasted demand.

- Under the Low Case projection, annual crude oil imports are forecast to increase by 34 million barrels between 2008 and 2015 (8.5 percent increase), by 55 million barrels by 2020 (13.6 percent increase), and by 91 million barrels by 2030 (22.5 percent increase compared to 2008).
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- Southern California is forecast to require an expansion of the existing crude oil import infrastructure to avoid detrimental impact on refinery operations. Although progress continues with regard to developing Berth 408 in the Port of Los Angeles, the time required to obtain all of the necessary permits to begin construction has been stretched to more than four years. In fact, Plains All-American still does not have all of the requisite approvals necessary for them to initiate construction.
- The increased imports of crude oil are expected to result in a greater number of marine vessels (referred to as crude oil tankers) arriving in California ports, 17 to 100 additional crude oil tanker arrivals per year by 2015, 28 to 162 by 2020, and 46 to 272 additional arrivals per year by 2030.
- Additional storage tank capacity would have to be constructed to handle the incremental imports of crude oil, between 1.5 and 5.8 million barrels by 2015; between 2.4 and 9.5 million barrels by 2020; and between 4.0 and 15.9 million barrels of storage capacity by 2030.
- The continued decline of California's crude oil production could be reversed through increased exploration and drilling in state and federal waters, but any appreciable impact on the level of imported oil would be at least a decade away. If the lifting of the moratoria on Outer Continental Shelf (OCS) drilling off the coast of California remains and expanded exploration and development is allowed to proceed, crude oil production off the coast could increase from 110,000 barrels per day in 2008 to approximately 310,000 barrels per day by 2020 and 480,000 barrels per day by 2030.
- If such an expanded drilling scenario were to be pursued by federal, state, and local governments, a new infrastructure of offshore oil production platforms, interconnecting pipelines, crude oil trunk lines, and pump stations would likely be required to achieve this forecast level of incremental crude oil production. It is unknown what portion of the untapped economically recoverable crude oil OCS reserves are close to any of the existing 22 offshore platforms (in federal OCS waters) such that directional drilling could be employed to increase production without constructing any new platforms and associated infrastructure.
- Even under this expanded federal OCS drilling scenario, California refiners would still need to import additional quantities of crude oil for the scenario that includes 0.45

percent per year refinery creep. However, the quantities required would be 16 to 22 percent lower than the initial crude oil import forecast by 2015, 80 to 119 percent lower by 2020, and 80 to 168 percent lower compared to the forecasted level of imports for 2030. This means that under the zero refinery capacity creep scenario, the expanded federal OCS drilling could decrease crude oil imports from 2008, but certainly not eliminate crude oil imports.

- If the Tranquillon Ridge Project were to move forward, offshore crude oil production from Platform Irene could increase by up to 28,000 barrels per day within one or two years. However, this increased crude oil supply from local sources will only reduce the forecasted level of crude oil imports in 2015 by 13 to 27 percent and in 2020 by 9 to 18 percent.

- Although an expansion of the federal Strategic Petroleum Reserve to the West Coast is not being actively pursued by Congress or the United States Department of Energy (U.S. DOE), the placement of strategic crude oil storage in California could decrease the likelihood of refinery production decline in the event of a temporary loss of crude oil deliveries to California. There has been no engineering analysis performed to date for quantifying an estimated range of cost for such a project.

Petroleum Product Import Forecast

- Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. In 2006, approximately 55 percent of Arizona's demand was met by products exported from California. However, that percentage dropped to just 35 percent by 2008 as refiners and other marketers shifted source of supply away from California and over to Texas and New Mexico.

- Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account East Line expansion plans, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market.

- The continued growth of transportation fuel demand in Arizona and Nevada could eclipse the capacity of some portions of the Kinder Morgan pipeline distribution system during the forecast period, absent additional expansions. Most segments are not expected to exceed maximum pumping capacity over the forecast period due to the recent, significant drop in transportation fuel demand and lower demand outlooks linked to increased use of renewable fuels and improved fuel economy standards for motor vehicles.

- Under the High Import Case analysis, California imports of gasoline are forecast to decrease significantly over the next 15 years, while imports of diesel and jet fuel would still need to rise to keep pace with growing demand for those products. Under the Low Import Case scenario, the growing imbalances between gasoline and the other transportation fuels are even more extreme, resulting in a net decline of imports of at least a quarter million barrels per day by 2015. It is recognized that this latter type of outcome is unlikely to materialize as refiners will adjust operations to decrease the ratio of gasoline components that are produced for each barrel of crude oil processed.

CHAPTER 2: Transportation Fuel Demand Trends and Forecasts

This chapter provides information on current economic, demographic, and transportation-related demand trends, as well as staff's proposed California transportation fuel demand cases for the *2009 IEPR*. Since these projections are based on updated input data and models, the uncertainties in the input values used in the demand models will also be discussed briefly.

California's transportation fuel demand has changed over time in response to growth in population, variation in fuel prices, evolving vehicle and fuel technologies, the health of the economy, and environmental regulations. These changes have collectively influenced both vehicle choice and driving behavior. Among the more important recent factors are the 2008 crude oil and fuel price volatility and recessionary economic conditions. For example, crude oil prices rose to over $140 per barrel in July 2008, before declining sharply to a level below $30 in December, but have since roughly doubled again to over $60 during July 2009. At its highest peak, in June 2008, the United States Energy Information Administration (U.S. EIA) reports the average price of California regular-grade motor gasoline was $4.48 per gallon. By December 2008 the price fell to $1.82, before rising again to $2.92 in June 2009. According to adjusted California Board of Equalization (BOE) data, California sales of gasoline fell by 6.3 percent from 2004 to 2008.

Forecast Uncertainties

In addition to uncertainties inherent in the data and specifications used in any forecasting model, there are uncertainties associated with the use of other public or private sector forecasts as inputs to these models. Changes in the regulatory environment, land use patterns, and fuel and vehicle technology, as well as the unusual transportation fuel price fluctuations add to the uncertainties of fuel demand forecasts.

Increasing environmental concerns have led California to assess and adopt a number of rules and regulations aimed at reducing harmful emissions. The latest in a series of rules and regulations is the adoption of low carbon fuel standard (LCFS). These California rules, to be fully enforced in 2012, will require all participants in the transportation fuels market to reduce carbon intensity measured by the sum of GHG emissions in all stages of transportation fuel production and consumption. This will involve different measures including the greatly increased use of alternative fuels and vehicle technology. By enhancing the existing surveys and models, staff has attempted to assess the markets for more vehicles and transportation fuels that can emerge to serve as alternatives to conventional petroleum fuels and vehicles. The absence of a long enough history and wide enough markets for these alternative and emerging vehicles and transportation fuels has limited consensus and added to the uncertainties associated with staff's analysis, beyond the uncertainties introduced by current economic conditions.

Uncertainties associated with crude oil and fuel price forecasts and the regulatory environment are addressed with scenario building, but manufacturer product offerings and economic and demographic projections are input into the model without expressly accounting for their inherent uncertainties. Potential changes in land use patterns and varying development of refueling infrastructure will also add to the uncertainties of the transportation fuel demand forecasts. The following section will outline some of the important projections used as inputs into the forecasts and discuss a few of their implications.

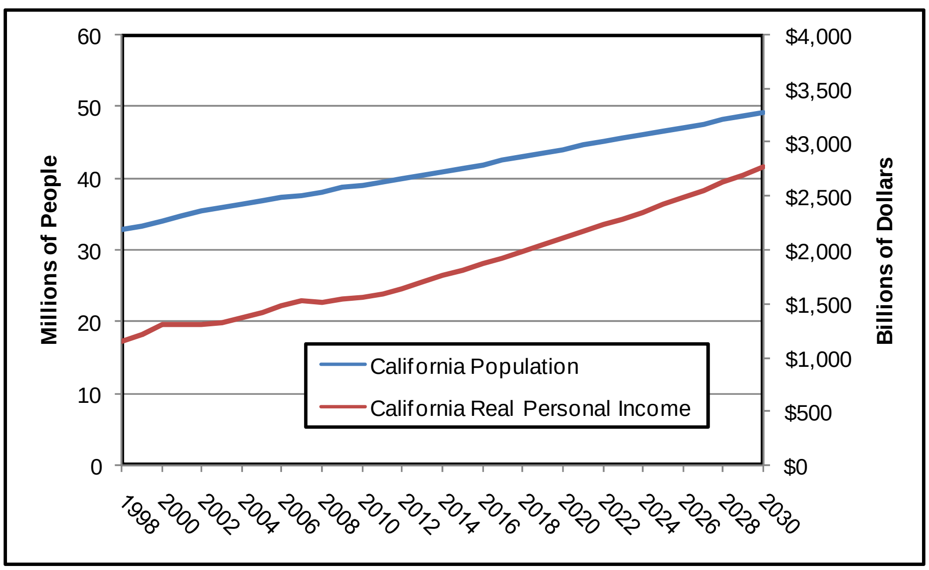
Current Transportation Trends and Projections of Input Variables

In this section staff provides information and data on trends of various transportation demand-related indicators, as well as economic, demographic, and other variables. The section also provides information on projections of important variables used as inputs for modeling transportation energy demand.

Actual and Projected Demographic and Economic Trends Related to Fuel Demand Forecasts

Between 1990 and 2008, California's population and personal income increased by 28 and 60 percent, respectively. Over the next 20 years (2009 to 2029), the California Department of Finance (DOF) and Moody's forecast growth of 25 and 76 percent, respectively, in California's population and income. Figure 2.1 shows actual and forecast data on personal income and population over the 1998-2030 periods. Between 2009 and 2030, population will increase at an annual compound average rate of 1.1 percent, compared with a growth rate of 2.9 percent in real personal income over the same period. These rates of growth remain significant and will result in substantial increases in travel demand for California.

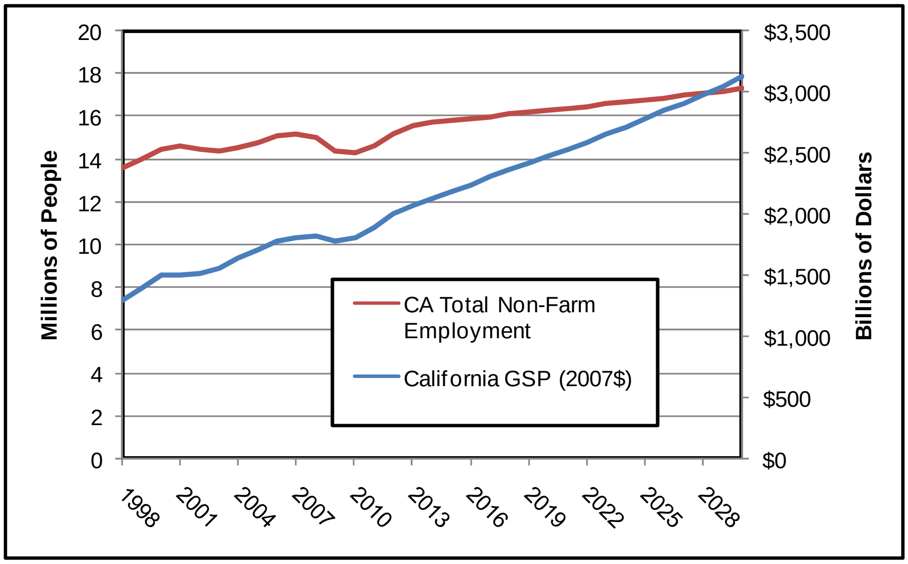
Figure 2.1: California Population and Income History and Forecasts 1998 to 2030



Source: Department of Finance and Moody's economy.com

From 1998 to 2008 California's Gross State Product (GSP) increased by 40 percent in real terms, rising from $1.3 trillion to $1.82 trillion (2007 dollars). Employment growth was much less pronounced during the same period and shows historical growth of 10 percent from 1998 and 2008. Figure 2.2 reflects the impact of recession on the 2009 and 2010 GSP and employment forecasts. Between 2008 and 2009 both GSP and employment declined, by 2.07 and 4.27 percent, respectively, and only GSP is projected to return to a positive growth by 2010.

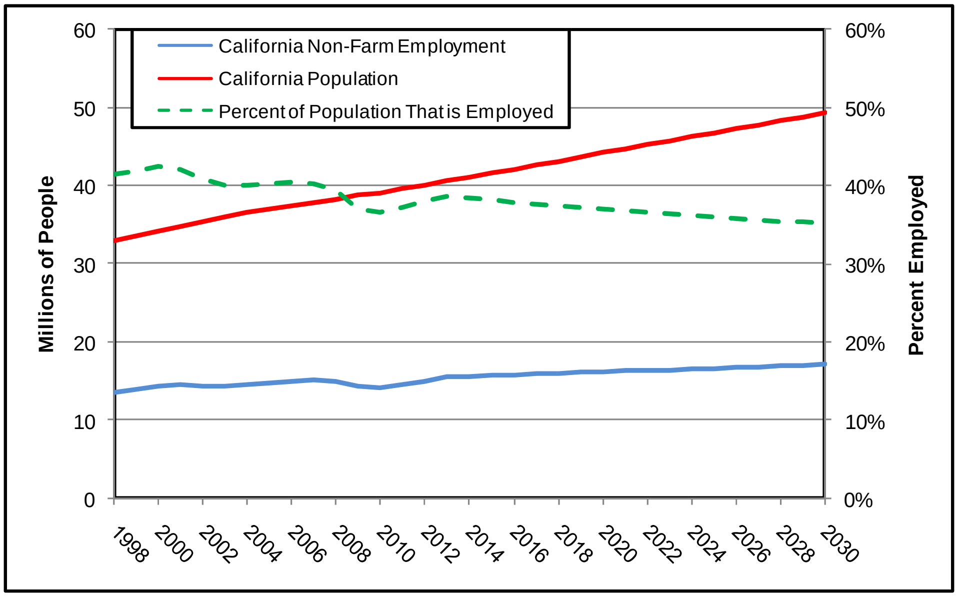
Figure 2.2: California GSP and Employment History and Forecasts, 1998 to 2030



Source: Moody's economy.com

Figure 2.3 shows the relationship between California's population and non-farm employment. This suggests that the forecasted growth in non-farm employment will not keep pace with the growth in population over the same period. Non-farm employment is projected to grow 20 percent during the forecast period of 2009-2030, in contrast with higher projected growth rates for both population and GSP. Total non-farm employment does not begin to exhibit positive growth until 2011 and does not return to 2008 levels until 2012.

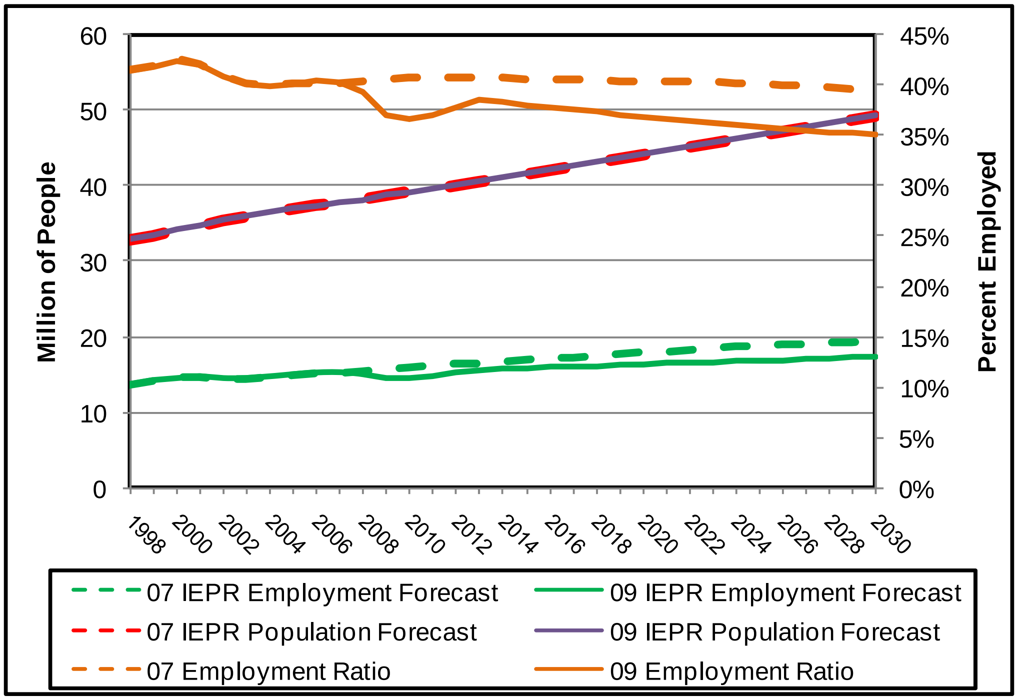
Figure 2.3: California Population and Employment History and Forecasts, 1998 to 2030



Source: Department of Finance and Moody's economy.com

Figure 2.4 contrasts 2007 and 2009 projections of population and employment. While the population growth to 2030 has remained the same between the two forecasts, non-farm employment projections have been lowered in the 2009 forecast, resulting in a sharp decline in the percentage of California population employed.

Figure 2.4: California Population, GSP, and Employment Projections Used in the 2007 and 2009 *IEPRs*



Source: Department of Finance and Moody's economy.com

Historical Light-Duty Vehicle Acquisition

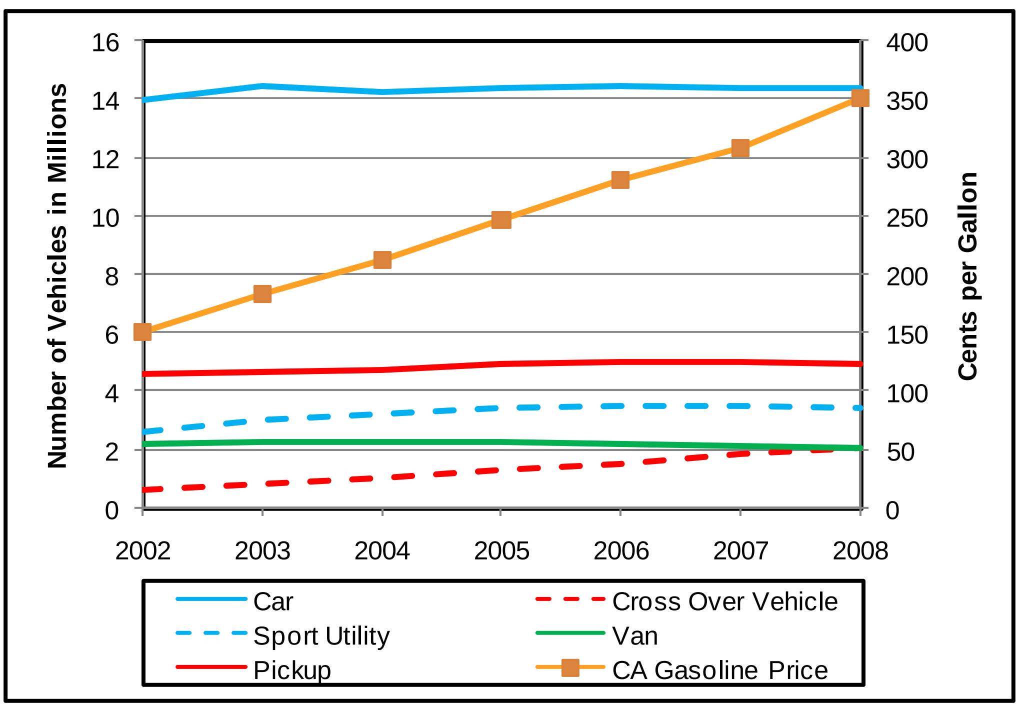
Staff reviewed recent trends in California vehicle acquisitions from the DMV Vehicle Registration Database.[2] The number of all alternative fueled vehicle types has increased in the state at rates substantially greater than for gasoline vehicles. Table 2.1 and Figures 2.5 and 2.6 provide information for on-road vehicle registration data from the California DMV for 2001 to 2008.

Table 2.1: Summary of California On-Road Light-Duty Vehicles

Light Duty Vehicle Counts						
	Gasoline	**Diesel**	**Hybrid**	**Flex Fuel**	**Electric**	**Natural Gas**
2001	22,779,246	316,872	6,609	97,611	2,905	3,082
2002	23,384,639	334,313	15,159	129,734	11,963	25,682
2003	24,516,071	364,411	24,182	183,546	23,399	17,228
2004	24,785,578	391,950	45,263	195,752	14,425	21,269
2005	25,440,904	424,137	91,438	269,857	13,947	24,471
2006	25,741,051	449,305	154,165	300,806	14,071	24,919
2007	25,815,758	465,654	243,729	340,910	13,956	25,196
2008	25,654,102	463,631	333,020	381,584	14,670	24,810
Compound Average Growth Rate	**1.71%**	**5.59%**	**75.06%**	**21.50%**	**26.03%t**	**34.71%t**

Source: California Energy Commission analysis of California DMV data

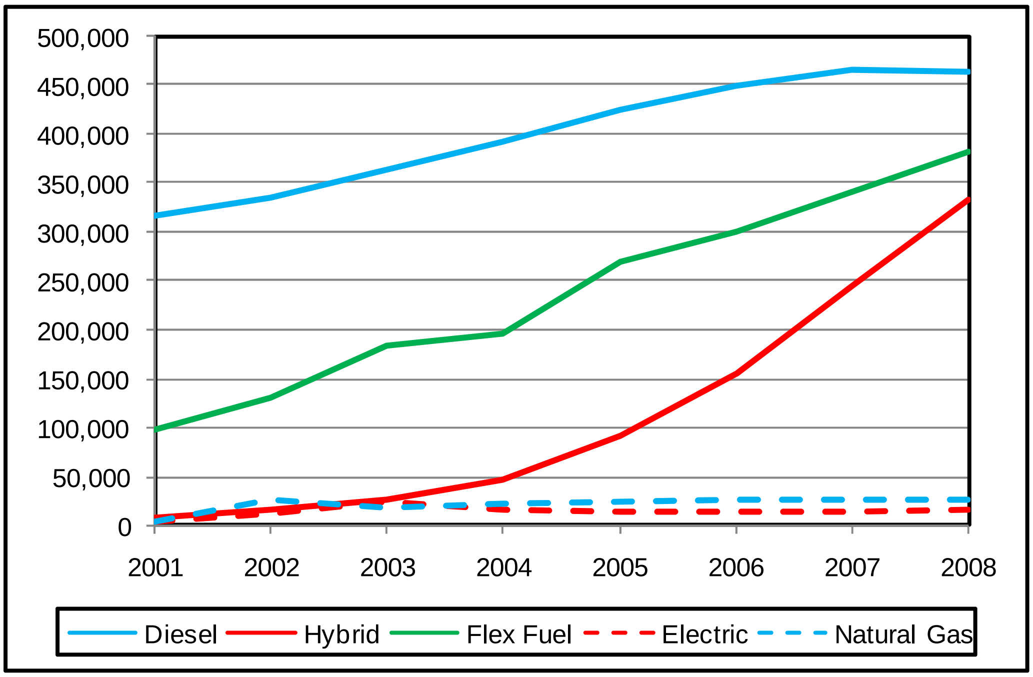
Figure 2.5: Population of California On-Road Light Duty Vehicles by Body Type (excluding gasoline)



Source: California Energy Commission analysis of California DMV data

Figure 2.6 shows the continued growth of FFVs and hybrid vehicles in California in 2008, but a slight decline in diesel light-duty vehicles in the same year. Ethanol used for FFVs, however, amounts to less than 10 gallons a year per vehicle in 2008, partly as a result of the disparity between FFVs and ethanol fuel station distributions in different counties. For instance, there is only one fuel station for the 90,000 FFVs registered in Los Angeles County. Natural gas and electric vehicles do not show a significant change between 2005 and 2008.

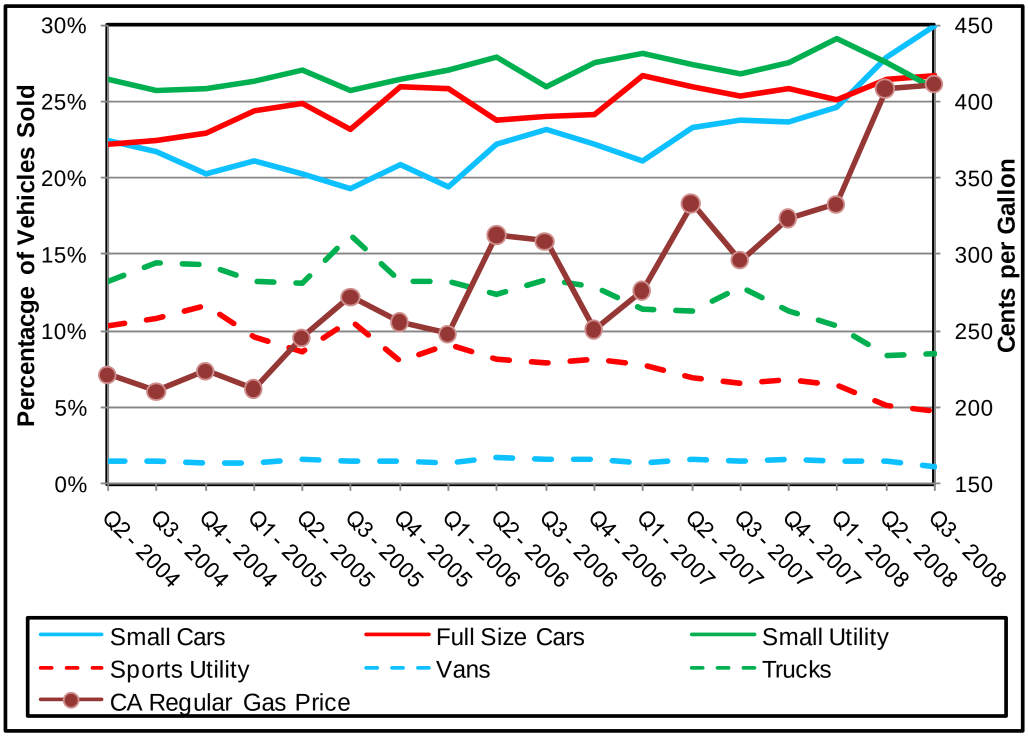
Figure 2.6: Population of California On-Road Light Duty Vehicles by Fuel Type (excluding gasoline)



Source: California Energy Commission analysis of California DMV data

Figure 2.7 shows the percentage by type of new vehicles sold by year and quarter starting from April 2004 to September 2008. Available data for 2008 indicate increased market share for cars, especially small cars, at the expense of trucks and utility vehicles.

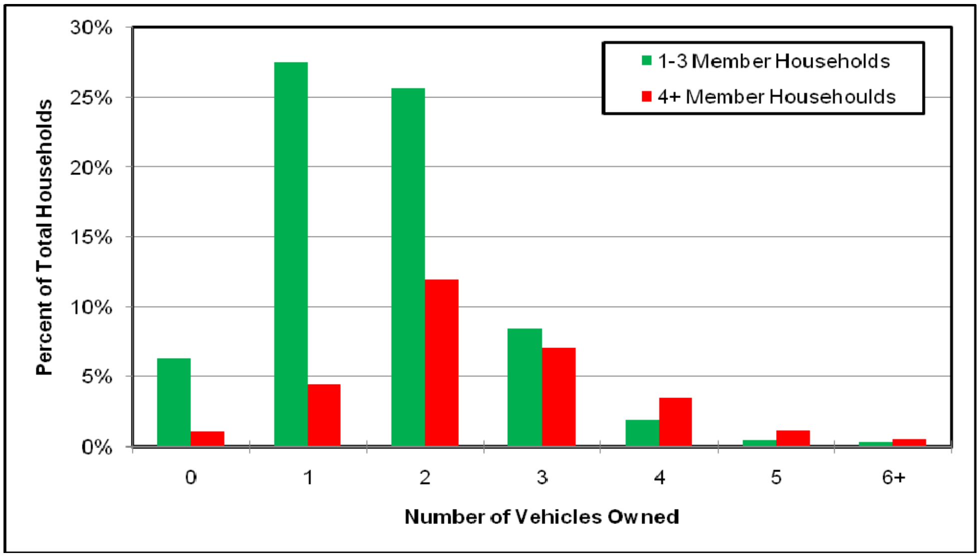
Figure 2.7: Percent of New Vehicles Sold by Vehicle Type



Source: California Energy Commission analysis of California DMV data

Figure 2.8 shows that the majority of California households have one to three members, and a majority of these households have two or fewer vehicles. Not surprisingly, a larger percentage of larger households own two or more vehicles.

Figure 2.8: Percent of California Households by Vehicle Ownership and Household Size, 2007



Source: American Community Survey, 2009

California Consumer Vehicle and Fuel Use Preferences

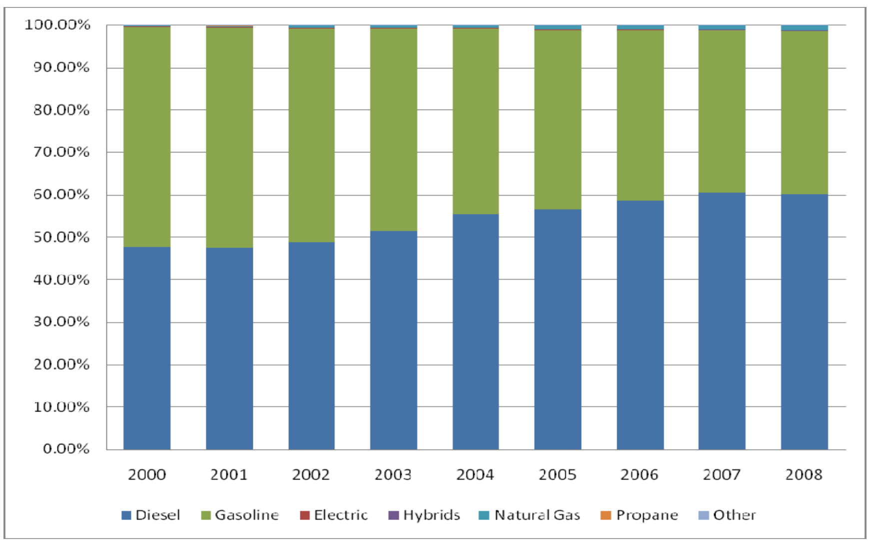
The 2008 CVS was conducted to capture California consumers' preferences for light-duty vehicles and transportation fuels. The survey collected data on the *revealed* preferences of 6,577 households and 3,452 commercial sector vehicle owners. Of these survey participants, 3,274 households and 1,780 commercial vehicle owners provided their *stated* preferences for vehicles of varying attributes. Survey data was used to model household and commercial sector vehicle choice and ownership behavior, as well as vehicle miles traveled by California households.

The CVS verifies the significant impact of distance to work and availability of transit on vehicle miles traveled. Therefore, changes in land use patterns that reduce the distance between locations of job and residence, and increase the availability of urban transit, will reduce vehicle miles traveled and transportation fuel consumption per capita. Fuel costs have a significant influence on both vehicle choice and vehicle miles traveled. California consumers, assuming equal prices and availability, do not differentiate significantly between E85 and gasoline in their preferences. Similarly, assuming all else equal, consumers more favorably view hybrid (including plug-in hybrids) and diesel vehicles but have less favorable impressions of compressed natural gas (CNG) and full electric vehicles, compared with gasoline vehicles. Vehicle price and fuel cost are both highly significant factors in the vehicle choice models, suggesting an awareness by California consumers of the tradeoff between these cost factors. The survey results showed that of all the incentives examined, the $1000 tax credit was viewed most favorably by all sizes of households and the High Occupancy Vehicle (HOV) lane use was most significant incentive for commercial sector buyers. Other incentives are more influential on vehicle choice decisions of the households that own more than one vehicle. The most important regional differences were in the higher consumer preferences for hybrid vehicles in San Francisco, and for HOV lane use incentive in Los Angeles.

Historical Medium- and Heavy-Duty Vehicle Stock

Medium- and heavy-duty vehicles are used primarily in the freight and transit sectors. Gross vehicle weight rating (GVWR) designates the maximum amount of weight for a vehicle in each vehicle class. Class 1 and 2 vehicles are vehicles that have a GVWR of 10,000 lbs or less and are generally described as light-duty vehicles, while classes 3 to 8 are assigned to vehicles with a GVWR greater than 10,000 lbs and described as medium- and heavy-duty vehicles. Figure 2.9 shows the medium and heavy- duty vehicle population percentages by fuel type for vehicle classes 3 to 8.

Figure 2.9: Percentage of All Class Type 3-8 (Medium- and Heavy-Duty) Vehicles by Fuel Type



Source: DMV Registration Database, File Pass for October 2008

Table 2-2 shows the vehicle populations for seven fuel types. Natural gas vehicles may use CNG or liquefied natural gas (LNG). Vehicles classified as "Other" use fuels not listed, such as methanol, hydrogen, and butane. The population of gasoline vehicles decreased from 52 percent in 2000 to 38 percent in 2008, with diesel vehicles making up most of the difference by rising from 48 percent in 2000 to 60 percent of vehicles in 2008. Alternative fuels make up around 1.4 percent of the vehicle population, with CNG and LNG combined having the largest share at 1 percent of the vehicle population. However, Table 2-3 indicates that many of the natural gas vehicles are registered to the government or transit districts primarily for urban transit use.

Table 2.2: Percentage of All Class Type 3-8 (Medium- and Heavy-Duty) Vehicles by Fuel Type

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Vehicle Population	808,512	819,104	867,426	884,919	851,568	920,784	952,082	982,456	952,191
Diesel	47.61%	47.35%	48.82%	51.33%	55.35%	56.53%	58.46%	60.51%	60.17%
Gasoline	51.98%	52.11%	50.41%	47.85%	43.78%	42.31%	40.35%	38.29%	38.48%
Electric	0.05%	0.05%	0.07%	0.08%	0.09%	0.11%	0.11%	0.11%	0.12%
Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Natural Gas	0.17%	0.16%	0.50%	0.57%	0.63%	0.79%	0.83%	0.87%	1.02%
Propane	0.17%	0.30%	0.18%	0.15%	0.14%	0.26%	0.23%	0.21%	0.20%
Other	0.02%	0.02%	0.02%	0.02%	0.00%	0.00%	0.02%	0.01%	0.01%

Source: DMV Registration Database, File Pass for October 2008

Table 2-3 shows the distribution of medium- and heavy-duty vehicles registered to individuals, government agencies/districts, and commercial entities. Vehicles registered to government include those used in urban transit, and vehicles registered to the commercial sector include those used in intercity transit. There are noticeable differences in the percentage distribution of fuel types in these sectors. The medium- and heavy-duty vehicle population owned by individuals has been continuously declining over time with the majority of vehicles using gasoline, while the percentage fueled by diesel appears to be increasing over time. The government vehicle population has the largest percentage of alternative fuel vehicles compared to all other sectors. The commercial/rental vehicle population shows an increase in the share of diesel vehicles, with gasoline vehicle use declining over time.

Table 2.3: Percentage of Type 3-8 (Medium- and Heavy-Duty) Vehicles by Fuel Type and Ownership Registration Type

		2000	2001	2002	2003	2004	2005	2006	2007	2008
Personal	Vehicle Population	244,817	275,806	213,748	229,508	201,326	193,091	190,965	187,721	178,897
	Diesel	4.38%	9.76%	7.63%	7.73%	10.19%	11.17%	12.80%	14.34%	15.48%
	Gasoline	95.59%	90.21%	92.29%	92.23%	89.78%	88.80%	87.18%	85.64%	84.51%
	Electric	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Natural Gas	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
	Propane	0.03%	0.03%	0.06%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%
	Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Government	Vehicle Population	105,494	100,776	130,455	128,448	130,142	147,921	150,789	153,143	158,568
	Diesel	48.88%	48.42%	51.32%	53.11%	53.40%	51.14%	51.03%	51.02%	50.45%
	Gasoline	49.12%	49.74%	44.75%	42.27%	41.96%	43.70%	43.49%	43.30%	43.56%
	Electric	0.37%	0.39%	0.47%	0.57%	0.60%	0.65%	0.65%	0.62%	0.61%
	Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Natural Gas	1.23%	1.07%	3.06%	3.57%	3.70%	4.11%	4.35%	4.59%	4.91%
	Propane	0.25%	0.25%	0.30%	0.39%	0.34%	0.40%	0.41%	0.42%	0.41%
	Other	0.15%	0.13%	0.10%	0.10%	0.01%	0.01%	0.06%	0.06%	0.06%
Commercial/Rental	Vehicle Population	458,201	442,522	523,223	526,963	520,100	579,772	610,328	641,592	614,726
	Diesel	70.42%	70.54%	65.02%	69.88%	73.32%	73.02%	74.58%	76.29%	75.68%
	Gasoline	29.35%	28.91%	34.71%	29.88%	26.44%	26.47%	24.92%	23.24%	23.78%
	Electric	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.04%
	Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Natural Gas	0.01%	0.05%	0.07%	0.09%	0.11%	0.21%	0.22%	0.24%	0.31%
	Propane	0.22%	0.48%	0.20%	0.15%	0.13%	0.30%	0.25%	0.21%	0.20%
	Other	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%

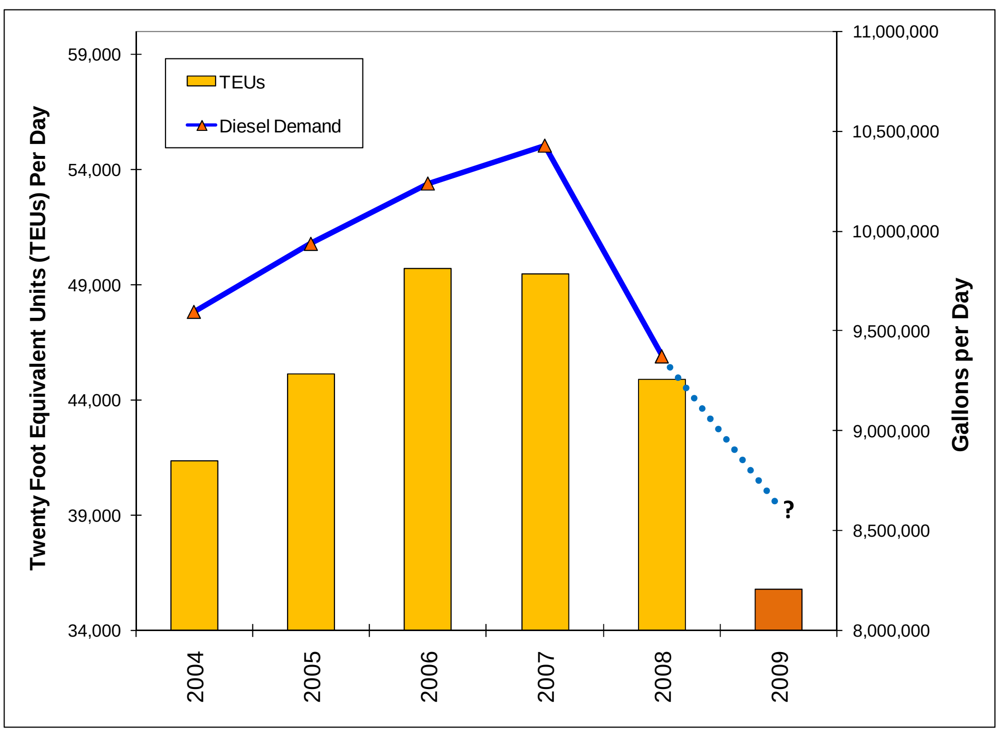
Source: California Energy Commission analysis of DMV Registration Database, File pass for October 2007

*Personal vehicles are vehicles registered to a single person.

Import Goods Movement and California Ports

A significant portion of the goods imported into the United States move through California ports, and these goods are then loaded onto trucks and railcars moving to destinations inside California as well as other states. Containerized goods handled through the ports of Los Angeles, Long Beach, and Oakland account for 42.2 percent of all port container activity during 2008 for the continental United States.[3] Nearly all cargo containers, referred to as twenty-foot equivalent units (TEUs), are handled at some point by either a truck or rail locomotive that is operating on diesel fuel. Therefore, the numbers of cargo containers that are imported (both full and empty) and exported through California ports are a reflection of economic activity and diesel demand in the state. Over the last couple of years, diesel fuel demand in California has demonstrated a good correlation with the total number of TEUs processed through the ports of Long Beach, Los Angeles and Oakland.[4] Since the taxable sales figures for California typically lag several months, cargo container statistics can be examined as a potential indicator of how strong or weak diesel fuel demand may be half way through 2009. Figure 2.10 shows the average daily numbers of TEUs processed by California's three largest container ports, along with the average daily demand for diesel fuel. As the chart shows, container activity is down significantly (27.6 percent) since 2007 when compared to the first half of 2009 and down 20.3 percent compared to the average for 2008.[5] This trend is another indication that diesel fuel demand for the first half of 2009 is appreciably lower than 2008 levels.

Figure 2.10: California Ports-Container Volumes and California Diesel Demand (2004-2009)



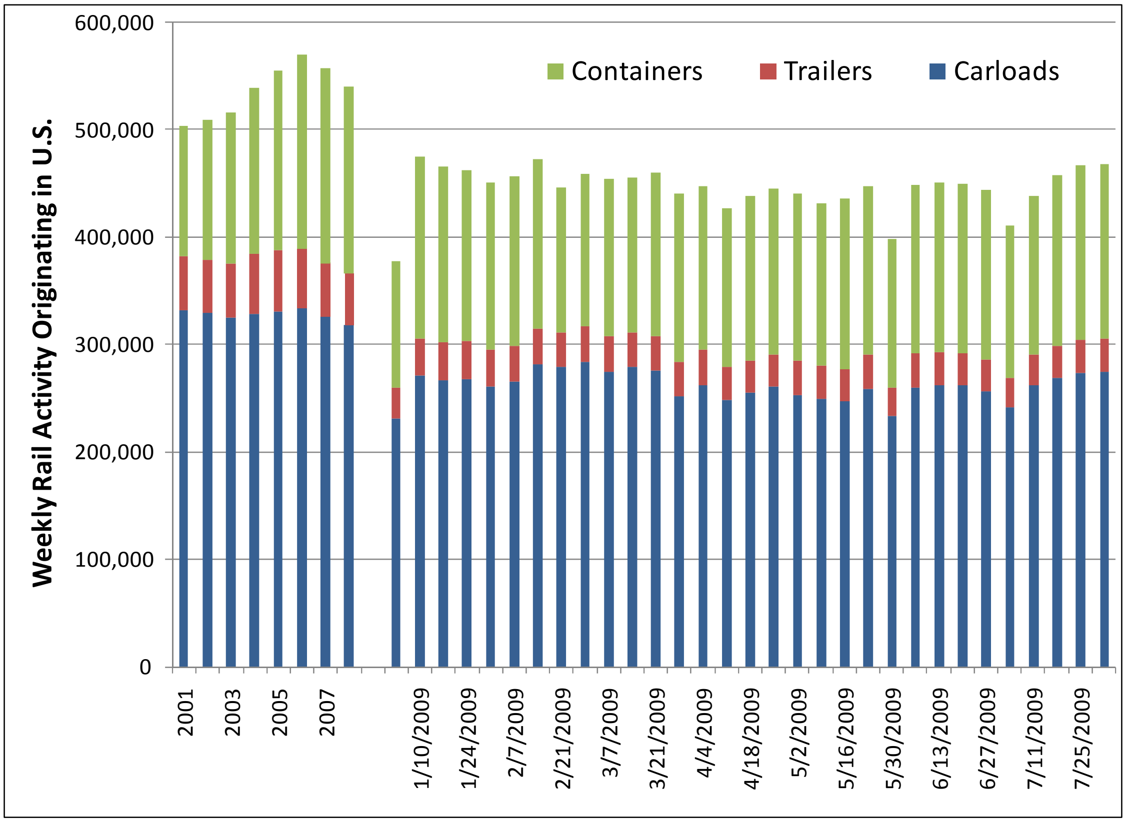
Sources: Ports of Long Beach, Los Angeles and Oakland; Board of Equalization (BOE), and Energy Commission analysis.

The U.S. Department of Commerce reports a GSP of $1,846 billion for the state of California in 2008 (Bureau of Economic Analysis, 2009). According to RAND, California imports are valued at $356 billion, which is more than 19 percent of California GSP. Most of the data on in-state freight movements primarily pertains to domestic freight and not international freight movement. Therefore, it is difficult to determine the share of total California freight movement from imported containers. However, with the growth in trade with China, California will remain a vital conduit for goods movement activities, and California ports will to continue to play a major role in the national and global economy.

Rail and Truck Activity

To determine whether diesel fuel demand is beginning to recover over more recent months, staff examined other sources of information that are considered good indicators or surrogates for diesel fuel demand in the United States. One of these measures is the level of rail activity used to move freight and bulk goods throughout the country. Figure 2.11 tracks the level of rail activity for rail cars originating in the United States since January 2001. The chart shows the average weekly numbers of carloads and intermodal units (both trailers and containers). The data indicates that rail activity has declined significantly since 2006. Most recently, year-to-date activity through the week ending August 1, 2009, shows that rail carload activity is down 19 percent compared to the same period in 2008. Intermodal rail activity is also down 17.2 percent compared to last year, while estimated ton-miles of rail activity declined 18.1 percent compared to 2008.[6] It does not appear as though rail activity is yet rebounding from the drop in economic growth, possibly signaling that diesel demand could remain lower than 2008 volumes for the United States and California.

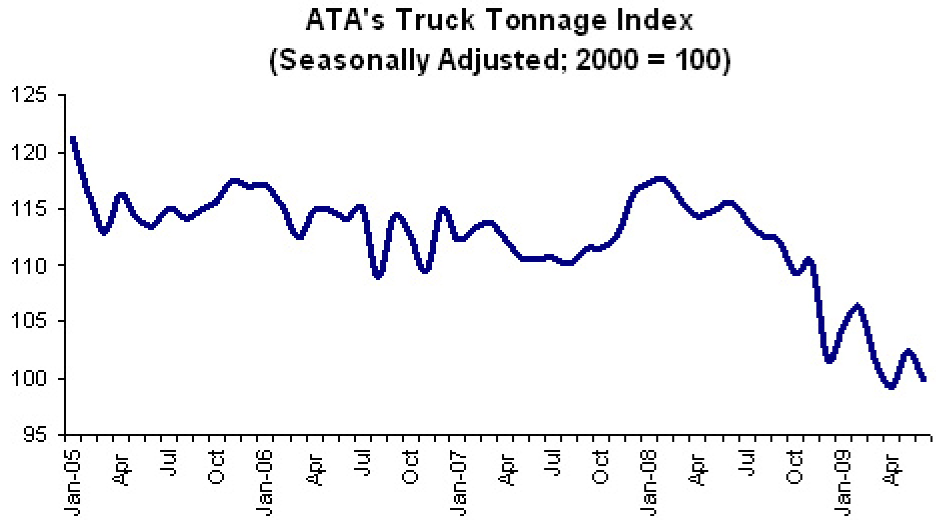
Figure 2.11: Rail Activity Originating in the United States (2001-2009)



Sources: American Association of Railroads (AAR) and Energy Commission analysis.

The American Trucking Association (ATA) tracks trucking activity in the United States. One of the instruments employed by this association is its survey of trucking companies used to assess movement of cargo and referred to as the seasonally adjusted For-Hire Truck Tonnage Index. Domestic trucking activity had been rather steady between 2005 and the first quarter of 2008. However, the rapid increase in diesel fuel prices in 2008 in conjunction with the severe downturn in the economy significantly reduced trucking activity. Figure 2.12 illustrates this point and appears to show that tonnage continues to decline, down 13.6 percent in June 2009 when compared to June 2008.[7]

Figure 2.12: U.S. Trucking Activity – Tonnage Index (2005-2009)



Source: American Trucking Association (ATA).

Transit

Nationwide, a combination of high fuel prices and a weak economy have reduced automobile travel while increasing transit travel. Transit ridership nationwide increased to 10.7 billion trips in 2008, a 4 percent increase over 2007, continuing the upward trend in transit ridership. Ridership in California mirrored nationwide trends; among 45 California transit agencies for which data was available from APTA, ridership increased by 2.2 percent, to 1.34 billion trips, between 2007 and 2008. This compares with the staff forecast of 2.3 percent increase in ridership from 2007 to 1.53 billion trips in 2008 (a forecast year in the model) for 63 rather than 45 agencies. APTA identifies the cities with the highest transit growth rates by different transit modes, and Table 2.4 shows California cities on the APTA list.

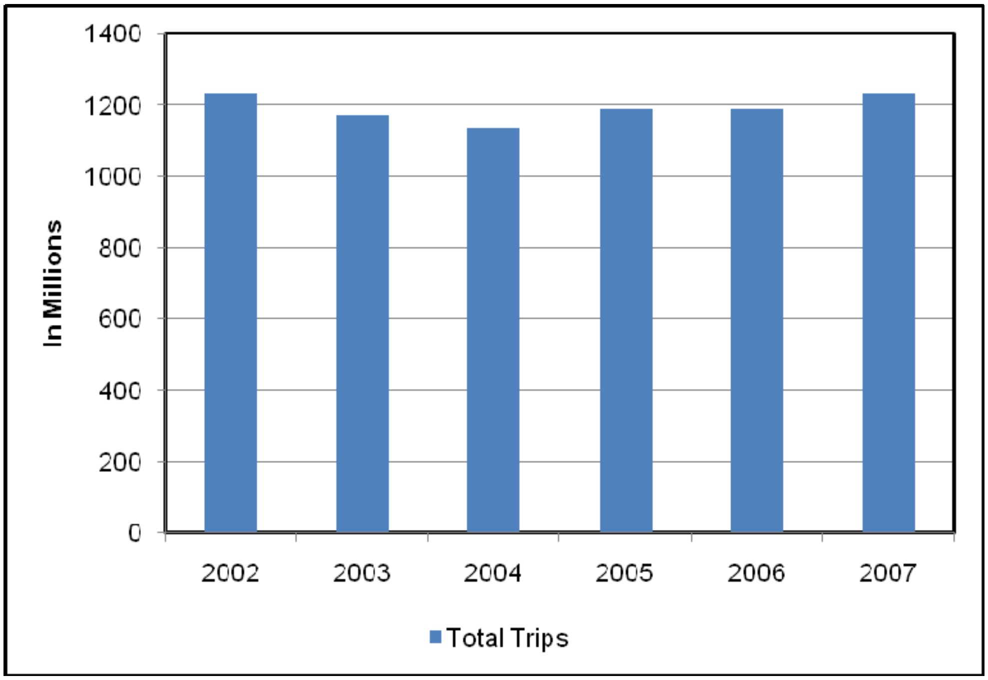
Table 2.4: 2008 California Top Transit Growth Cities, by Transit Mode

City	Growth Rate (percent)	Transit Mode
Oakland	16.1	Commuter Rail
Stockton	14.7	Commuter Rail
Sacramento	14.4	Light Rail
San Diego	10.0	Bus
Los Angeles	7.7	Heavy Rail

Source: American Public Transit Association, http://www.apta.com/media/releases/090309_ridership.cfm, March 2009

Figure 2.13 shows recent trends in total unlinked transit trips for California as reported by the Federal Transit Administration.

Figure 2.13: Transit Ridership in California

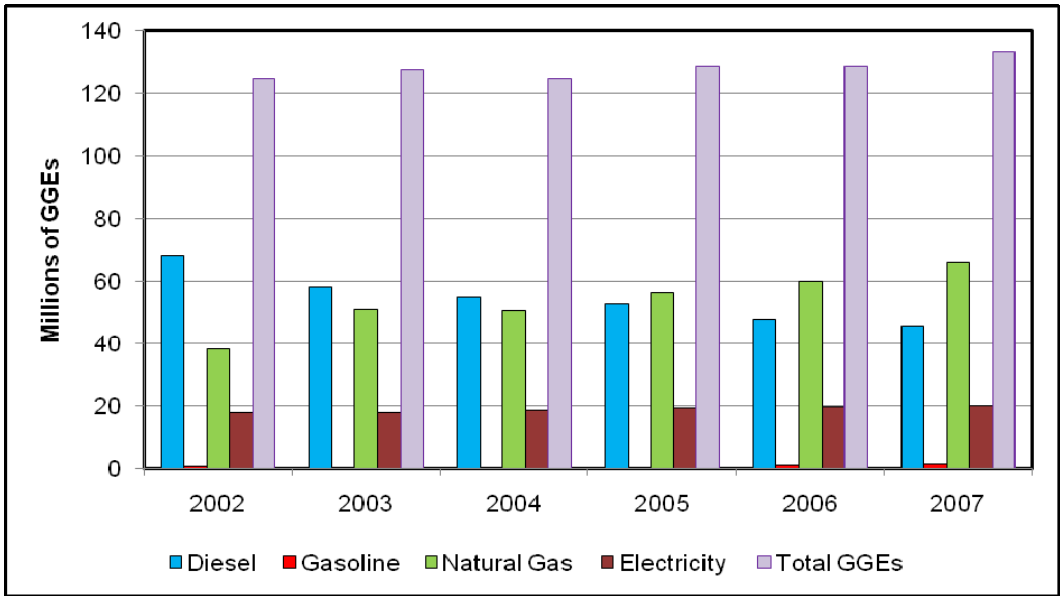


Source: Federal Transit Administration, National Transit Database, http://204.68.195.57/ntdprogram/data.htm

*Total unlinked trips, reported by 82 transit agencies in California. A few agencies have not regularly reported ridership, and the ridership has been estimated for these missing reporting years, using statewide average ridership growth rates.

Figure 2.14 shows the trend in urban transit fuel consumption, corresponding to increasing ridership. It also shows that natural gas has been replacing diesel in the transit fleet, while the rise in electricity consumption corresponds with the growth in light rail.

Figure 2.14: Urban Transit Fuel Consumption in California, by Fuel Type



Source: Federal Transit Administration, National Transit Database, http://204.68.195.57/ntdprogram/data.htm

*Natural gas consumption indicates the total for CNG and LNG.

The 2008 CVS reveals some patterns in the relationships between vehicle ownership, household size, miles-to-work, and transit use. Table 2.5 shows miles to work were highest in the Los Angeles and Sacramento regions. Transit use is highest in the San Francisco region where transit accessibility and population density are both high, and lowest in the "rest of state" where transit availability and population density are both low. No significant difference is observed in miles traveled to work by household size; however, households with two or three persons have the highest rate of transit use. The number of vehicles in a household has a strong relationship with both the miles traveled to work and transit use. Vehicle ownership is positively related to the mean miles traveled to work, and transit use decreases with increased number of vehicles available to the household.

Table 2.5: Miles-to-Work and Transit Use in California in 2008

Region	Mean Vehicle Miles to Work	Percent Transit Use
San Francisco	14.23	8.9%
Los Angeles	15.44	2.3%
San Diego	14.38	2.5%
Sacramento	15.29	2.7%
Rest of State	14.51	1.3%
Overall Statewide	14.87	3.6%
Household Size	**Mean Vehicle Miles to Work**	**% Transit Use**
1	14.94	2.0%
2	14.76	3.4%
3	14.88	3.3%
4+	14.98	2.4%
Number of Vehicles	**Mean Vehicle Miles to Work**	**% Transit Use**
1	12.85	4.8%
2	14.60	2.8%
3+	17.20	2.0%

Source:California Energy Commission, 2008 California Vehicle Survey

Aviation

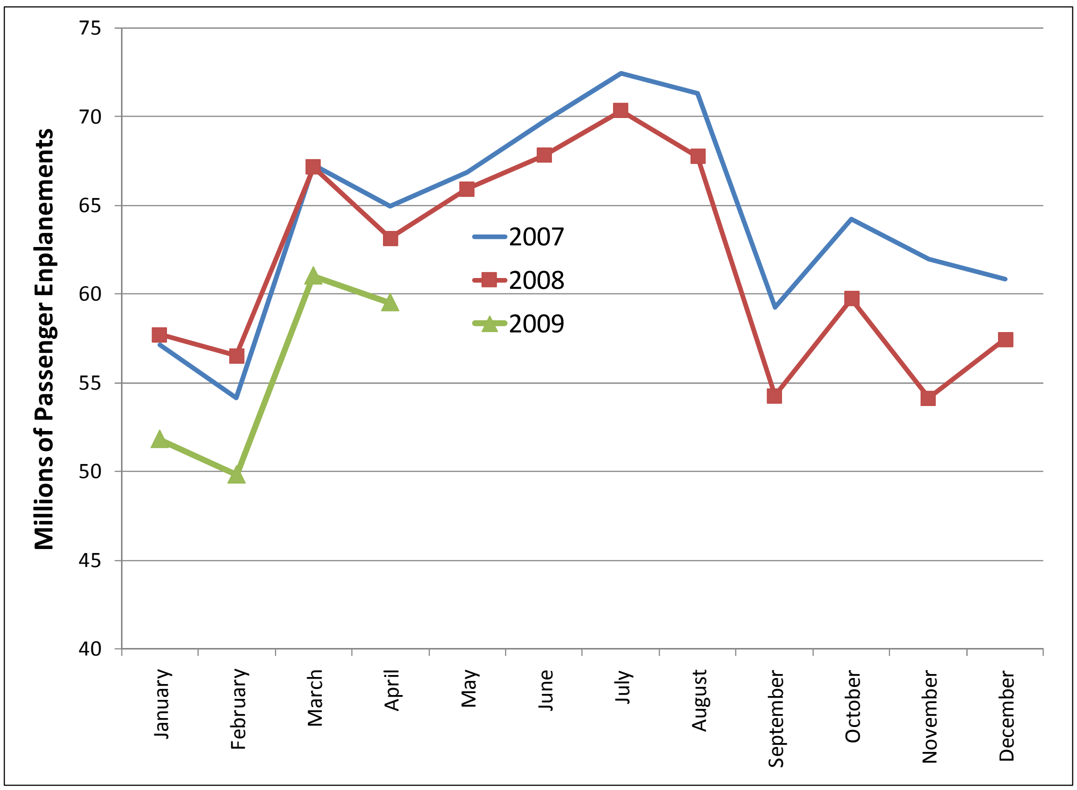
The aircraft fleets of commercial air carriers transporting passengers and cargo are powered by jet turbines and turboprops, both of which run on kerosene-type jet fuel. General (or private) aviation is increasingly dominated by jet turbine and turboprop engines, as the numbers of gasoline aircraft decrease; some general aviation aircraft are air taxis transporting passengers for hire. Wide-body jets of the 1970s and 1980s have largely been replaced in domestic service but persist in international passenger operation and air cargo. Narrow-body jets such as the Boeing 737 and Airbus 240 have come to dominate domestic passenger travel. The next generation of lighter and more efficient aircraft, such as the Boeing 787, is in production and may provide up to 25 percent reduction in fuel use per passenger mile.

Airlines have responded to fuel price increases of recent years by reducing both the number of empty seats and the number of flights. In response to decreased demand, airlines have financial reasons for taking the least efficient aircraft out of service. The converse is also true, that as demand increases the newest and generally most efficient of remaining aircraft is placed back into service. As a result the overall rate of fuel use per passenger mile may increase in the short term with an increase in demand.

The growth of air cargo service, measured in ton miles, has come from increased Internet commerce, the growth of the package industry in general, and the development of niches such as perishable soft fruits, seafood, and prototype electronics. Adding to these growth drivers is the growth in Pacific Rim commerce, which funnels an increasing fraction of the nation's imports into and through California airports. Additionally, greater amounts of cargo will likely be transported by air freight-only carriers due to the requirement that by 2010 100 percent of cargo must be screened when placed into passenger aircrafts.

Airline activity is usually a good barometer for jet fuel demand. The United States Bureau of Transportation statistics compiles information from airline companies operating in the United States. One of the better measures of air activity is the number of people boarding flights that originate in the United States and are destined for locations both domestic and international. Referred to as passenger enplanements, the most recent data for 2009 indicate that passenger activity continues to be lower than the preceding two years. Figure 2.15 illustrates that airline passenger activity has not yet begun to recover from a steady decline from 2007. For the first four months of 2009, total passenger enplanements are down 9.1 percent compared to the same period in 2008.[8]

Figure 2.15: U.S. Airline Passenger Enplanements (2007-2009)



Source: United States Bureau of Transportation Statistics.

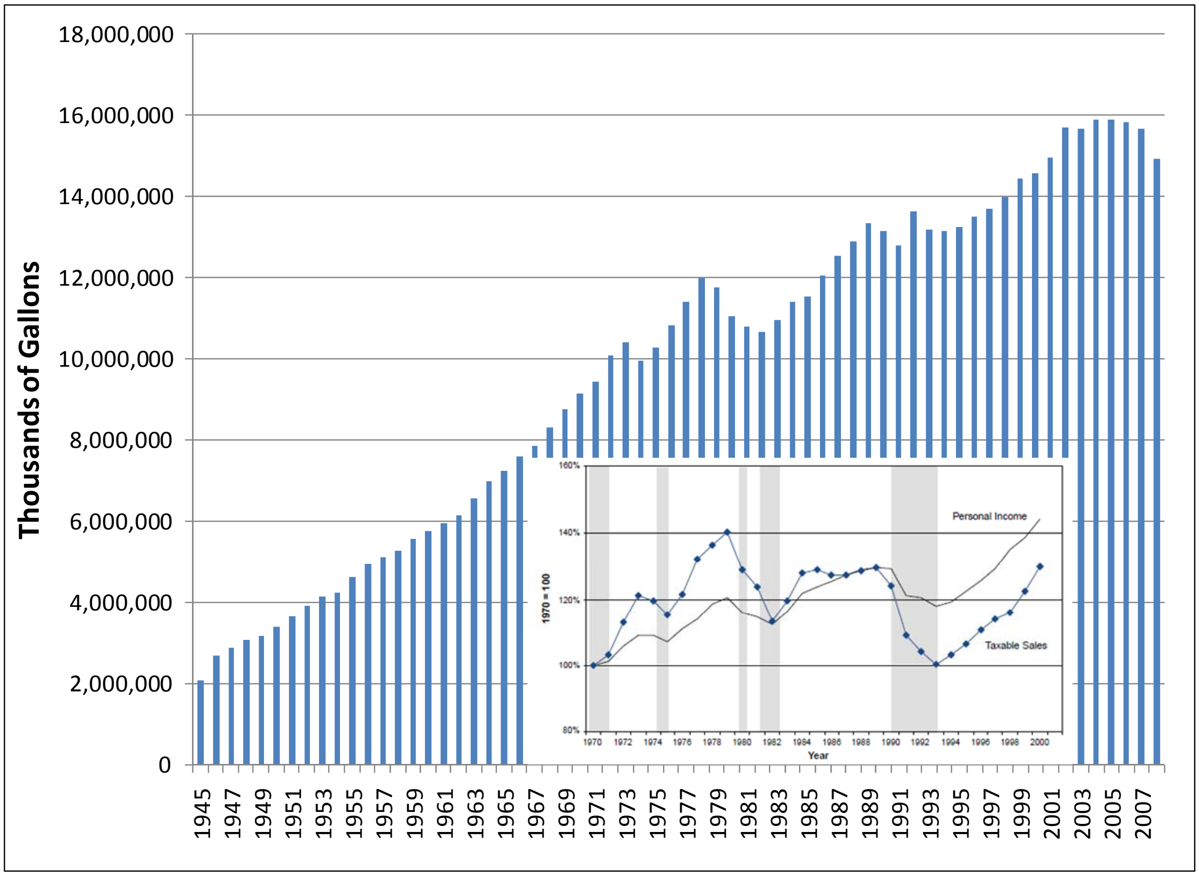
Recent Demand for California Transportation Fuels

Demand for traditional petroleum-based transportation fuels (gasoline, diesel, and jet fuel) has recently declined as a consequence of several factors. Lower demand levels reduce the need to import blending components and finished petroleum products that augment local refinery production supply.

Gasoline Demand

Over the last several decades, there have been occasional stretches when gasoline demand declined from one year to the next. It has been unusual that California has experienced any periods when gasoline demand declined for multiple consecutive years. The longest sustained demand decline was from 1978 through 1982. As expected, these downturns in gasoline demand appear to be closely associated with California's periods of recession that have resulted in lower levels of personal income.[9] Figure 2.16 depicts how California's gasoline demand has grown since the end of World War II, rising from 2.06 billion gallons in 1945 to a peak of 15.91 billion gallons in 2004.

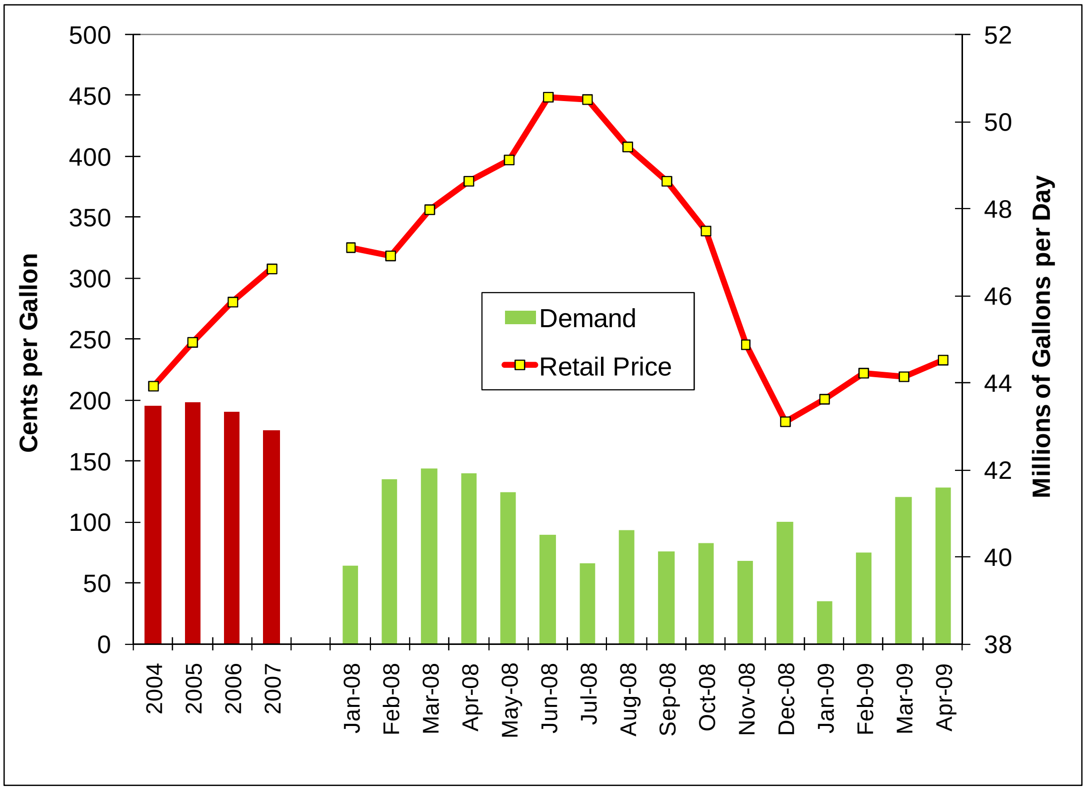
Figure 2.16: California Gasoline Demand and Recessions (1945-2008)



Sources: Federal Highway Administration, California State Board of Equalization, and Energy Commission analysis.

Staff has recently completed analysis of the taxable gasoline sales data compiled by BOE. Adjustments were mainly made to compensate for large audits that were reported as "sales" during a single month but were in fact a compilation of new or rectified accounting records that took place over several months or years. This new analysis has resulted in slight revisions to the BOE taxable gasoline sales figures that are available at the BOE website.[10] Figure 2.17 shows the total annual gasoline demand and retail prices for 2004 through 2007 and monthly figures thereafter. California average daily gasoline demand for the first four months of 2009 is 2.1 percent lower compared to the same period in 2008, continuing a declining trend since 2004. In fact, over the last 12 months (May 2008 through April 2009) gasoline demand is down 4.6 percent compared to the previous 12-month period (May 2007 through April 2009).[11]

Figure 2.17: California Average Daily Gasoline Demand and Price (2004-2009)

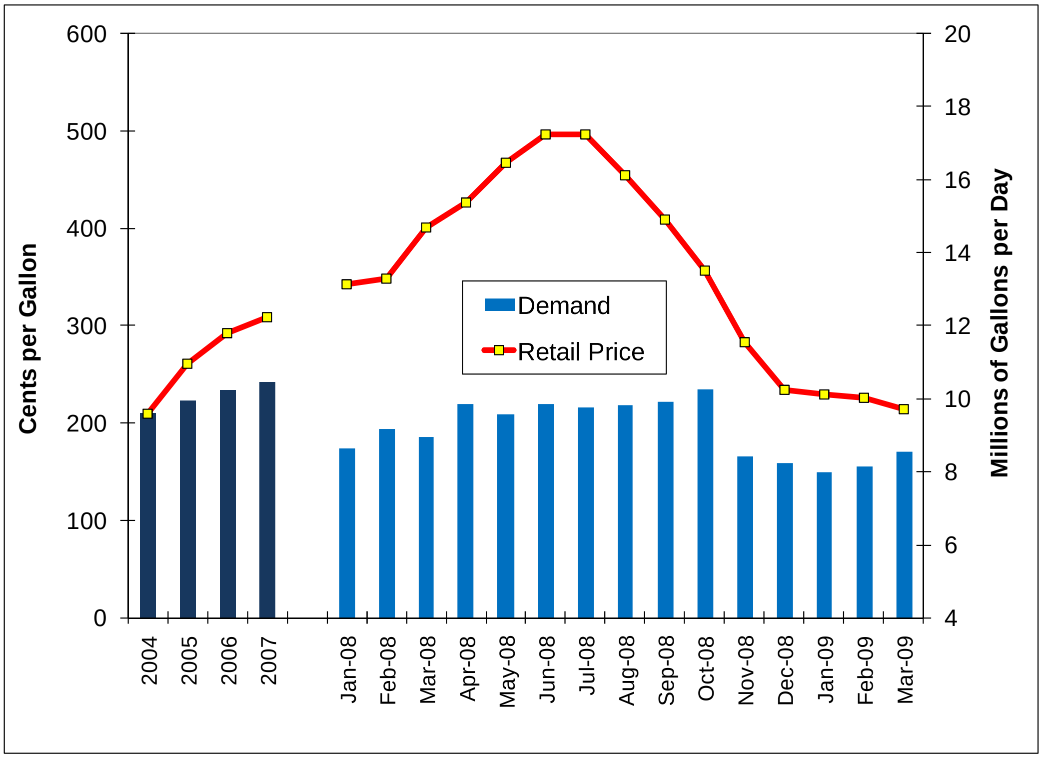


Sources: California State Board of Equalization and Energy Commission analysis.

Diesel Fuel Demand

As was the case with gasoline, staff adjusted monthly diesel fuel sales figures to include additional volumes of red dye diesel fuel that is not included in BOE taxable sales figures since the first sale of diesel fuel intended for use in an exempt manner is not a taxable event. However, to better assess monthly demand for diesel fuel, it is appropriate to include these red dye volumes. Figure 2-18 shows the total annual diesel fuel demand and retail prices for 2004 through 2007 and monthly figures thereafter. California average daily diesel fuel demand for the first three months of 2009 is 7.7 percent lower compared to the same period in 2008, continuing a declining trend since 2007. Over the last 12 months (April 2008 through March 2009) diesel fuel demand is down 10.2 percent compared to the previous 12-month period (April 2007 through March 2009).[12]

Figure 2.18: California Average Daily Diesel Demand and Price (2004-2009)

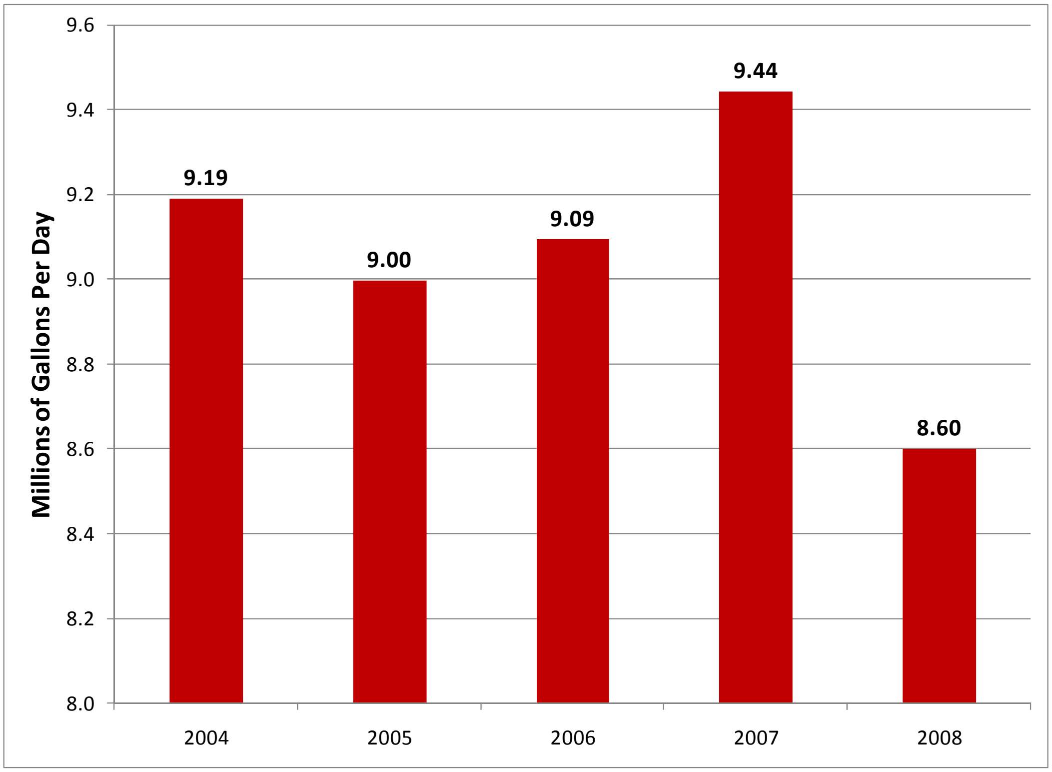


Sources: California State Board of Equalization and Energy Commission analysis.

Jet Fuel Demand

The third type of traditional petroleum-based transportation fuel is commercial jet fuel or Jet A. California refiners also produce limited quantities of military grade jet fuel, referred to as JP-5 and JP-8. For examining recent and forecasted jet fuel demand quantities and trends, only commercial jet fuel was included. Recent demand trends for jet fuel are similar to diesel fuel and reflect an overall downturn in the domestic and California economies. After rising 5 percent between 2005 and 2007, California jet fuel demand declined 8.9 percent in 2008 compared to the previous year. Figure 2.19 shows the annual demand for commercial jet fuel in California from 2004 through 2008.

Figure 2.19: California Commercial Jet Fuel (Jet A) Demand (2004-2008)



Sources: Petroleum Industry Information Reporting Act data and Energy Commission analysis.

Transportation Demand Forecasts

Approach to Forecasting and Assumptions

The transportation demand forecasts prepared for this staff draft report encompass four primary transportation sectors.

- Light-duty vehicles
- Medium- and heavy-duty transit vehicles
- Medium- and heavy-duty freight vehicles, including rail
- Commercial aviation

Each of these sectors is associated with a distinct forecasting model which estimates the demands for that individual transportation sector. The California Conventional Alternative Fuel Response Simulator (CALCARS), Freight, Transit, and Aviation models represent each of the corresponding transportation sectors. Appendix A provides a description of these models and their updates.

Staff has developed forecasts over a range of fuel prices used in forecasting transportation energy demand in California. Appendix B details all fuel price cases developed for use in the forecasts. Additionally, economic and demographic projections from DOF and Moody's Economy.com were extended to 2030 to cover the forecast period. Survey responses and information represent the forecasted period of California. As with past transportation fuel demand forecasts, K.G. Duleep of ICF International provided historic and projected vehicle characteristics used in the CALCARS model. Appendix A briefly discusses the vehicle characteristics included in the model evaluation.

In 2004, ARB adopted the California GHG standard for light-duty vehicles (AB 1493, Pavley, Chapter 200, Statutes of 2002). The standard requires a gradual reduction of GHG equivalent emissions beginning in 2009, which by 2016 results in approximately a 30 percent reduction in emissions per mile for the average new vehicle as compared to today's new vehicles. The levels of fuel economy used in this report for light-duty vehicle demand cases considering the GHG standard are based on the levels of average fuel economy improvement, which could allow compliance with the standard, as well as the ZEV mandate.

Staff's original intent was to use the CALCARS model updated with the 2008 CVS results in this preliminary forecast. The survey (which is described briefly on p. 33) obtained information on respondents' attitudes and preferences regarding several alternative fuel technologies, including hybrids, plug-in hybrids, full electric vehicles, flex fuel vehicles, and CNG vehicles. This data will enable staff to forecast demand across the breadth of transportation fuels, not just for conventional petroleum fuels. For a variety of technical reasons, this proved to be impossible in time for inclusion in this staff draft report. Therefore, light-duty vehicle fuel demand in this report will necessarily be limited to gasoline, diesel, and renewable fuels. The transit, rail freight, and aviation fuel demand forecasts were not affected by these limitations on the light-duty forecast.

Staff's proposed light-duty vehicle gasoline and diesel fuel demand forecasts have been adapted from the final staff report prepared for the *2007 IEPR*.[13] The single 2007 forecast case most nearly representative of the fuel prices and GHG reduction policies for current conditions, that is the high fuel price case with GHG rules, is the basis for the proposed 2009 light-duty gasoline and diesel demand forecasts. To account for the lowered expectations of demand in response to recessionary economic conditions, the gasoline and diesel demand trajectories are initiated from 2008 actual data points. Fuel price assumptions for this 2007 case were roughly intermediary between high and low price assumptions for this 2009 report, therefore high and low gasoline demand bands for the current forecast are calculated equally at 15 percent above and below the 2007 gasoline demand forecast, phased in over 8 years. For on-road diesel, the high and low bands were calculated at 20 percent above and below the 2007 on-road diesel demand forecast, phased in over 8 years. California carbon emission rules assumed for the 2007 case are similar to those assumed in both proposed 2009 demand cases. Other than the employment projections, future economic and population growth are roughly similar, given the initial year adjustment of the forecast to account for the fuel demand decline in response to the current recession.

Petroleum Fuel Demand Forecasts

In general, the early years of the demand forecast represent a recovery from the current recessionary economic conditions. Because the economic and demographic projections used in these forecasts indicate the return of reasonably healthy economic growth and steady population growth, the trends for the freight and aviation sectors tend to resume historical patterns of increase in fuel demand. Gasoline demand in the light-duty sector, however, is more heavily influenced by the introduction of competing technologies, efficiency improvements, and by higher projected fuel prices. As a result, the gasoline demand forecast tends to decline in later years.

Gasoline Demand Forecast

Table 2.6 reports the light-duty gasoline consumption forecast in California, and Table 2.7 and Figure 2.20 show total forecasted gasoline consumption. Between 2007 and 2030, total gasoline consumption in California falls by 33.6 percent in the low demand case as increased efficiency and continued fleet hybridization and dieselization reduce gasoline demand. This is a rather dramatic decline in gasoline consumption but roughly corresponds to levels of gasoline demand projected in the *State Alternative Fuels Plan* Moderate Case. [14] In the high demand case, the recovering economy and lower fuel prices lead to a gasoline demand peak in 2016 before falling to 14.02 billion gallons in 2030, 10.4 percent below 2007 levels.

Table 2.6: California Light-Duty Vehicle Gasoline Demand Forecast

Year	Low Demand Case		High Demand Case	
2007	15,408,916,800		15,408,916,800	
2010	13,978,451,088	-9.28%	14,512,659,410	-5.82%
2015	12,126,644,866	-13.25%	15,201,005,537	4.74%
2020	10,767,884,875	-11.20%	14,568,314,831	-4.16%
2025	10,326,860,295	-4.10%	13,971,634,516	-4.10%
2030	10,251,291,084	-0.73%	13,869,393,820	-0.73%
Average Annual Growth Rate	-1.76%		-0.46%	

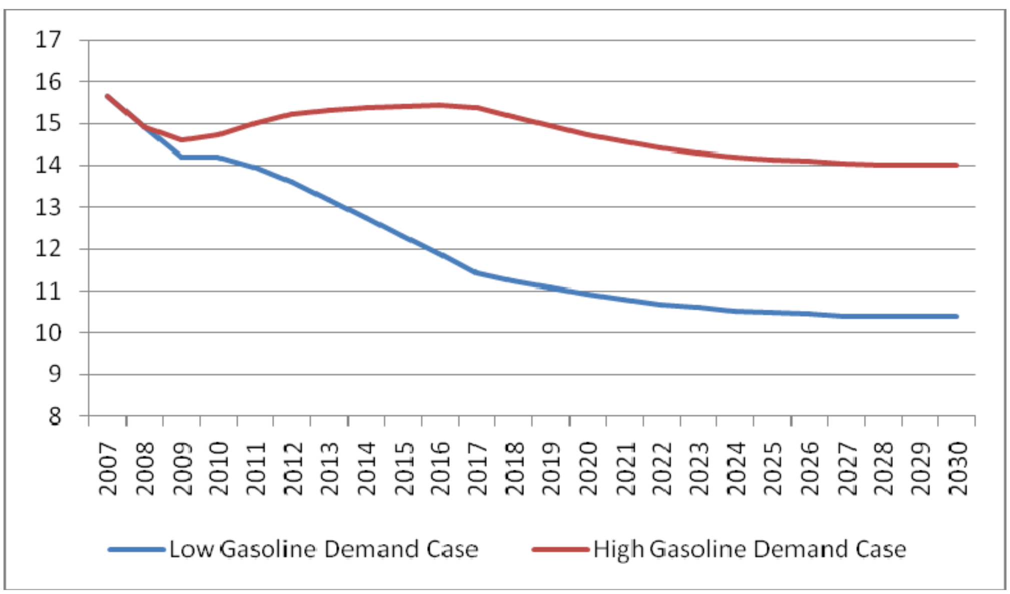
Source: California Energy Commission

Table 2.7: Total California Gasoline Demand Forecast (Gallons)

Year	Low Demand Case	Change from Previous Value	High Demand Case	Change from Previous Value
2007	15,658,306,800		15,658,306,800	
2010	14,196,621,088	-9.33%	14,731,069,410	-5.92%
2015	12,310,084,866	-13.29%	15,385,565,537	4.44%
2020	10,928,154,875	-11.23%	14,730,314,831	-4.26%
2025	10,479,320,295	-4.11%	14,126,394,516	-4.10%
2030	10,402,381,084	-0.73%	14,023,343,820	-0.73%
Average Annual Growth Rate	-1.76%		-0.48%	

Source: California Energy Commission

Figure 2.20: Total California Gasoline Demand Forecast (Billion Gallons)



Source: California Energy Commission

Diesel Demand Forecast

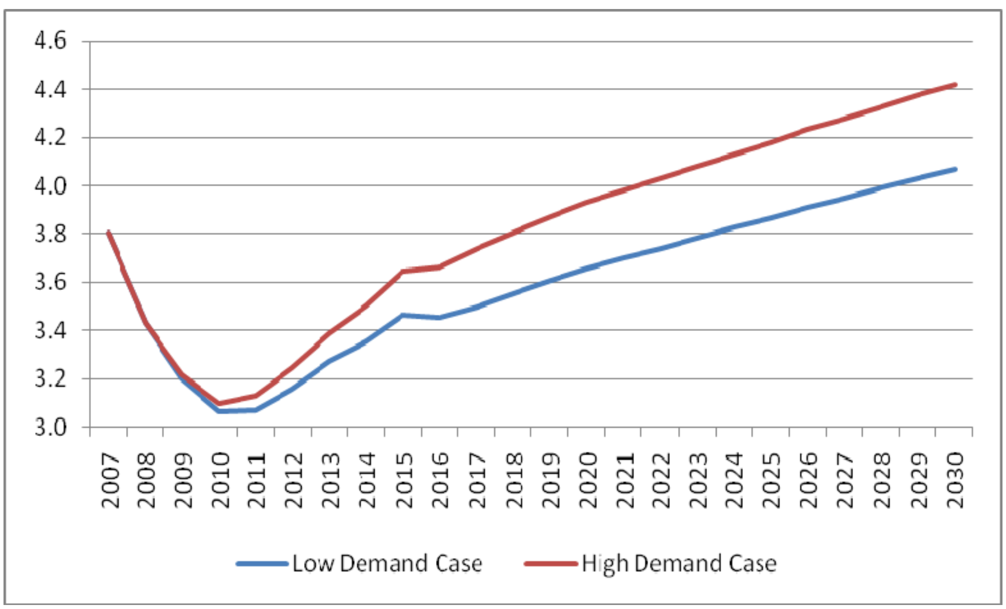
The diesel demand forecast represents four primary areas: truck and rail freight goods movement, residential and commercial light-duty vehicle transportation, urban and intercity public transit, and off-road use of diesel (mostly in construction and agriculture). Of these four sectors, goods movement is by far the most significant, representing over 83 percent of all consumption in the 2007. Table 2.8 and Figure 2.21 show the total California diesel demand forecast. Between 2007 and 2030, total diesel demand is forecast to increase by 7 percent in the low demand case and 16 percent in the high demand case.

Table 2.8: California Diesel Demand Forecast (Gallons)

Year	Low Demand Case	Change from Previous Value	High Demand Case	Change from Previous Value
2007	3,805,503,272		3,805,503,272	
2010	3,063,496,445	-19.50%	3,094,478,520	-18.68%
2015	3,466,779,643	13.16%	3,643,888,124	17.75%
2020	3,656,918,633	5.48%	3,927,647,794	7.79%
2025	3,868,000,344	5.77%	4,179,211,849	6.40%
2030	4,070,671,562	5.24%	4,418,944,141	5.74%
Average Annual Growth Rate	0.29%		0.65%	

Source: California Energy Commission

Figure 2.21: California Diesel Demand Forecast (Billion Gallons)



Source: California Energy Commission

Jet Fuel Demand Forecast

Since jet fuel is formulated to national and international standards, jet fuel demand forecasts do not take into account California GHG standards but do incorporate high and low jet fuel price scenarios as well as two aviation fuel efficiency forecast cases. Assumptions of high jet fuel prices and fuel efficiency imputed from United States Federal Aviation Administration (FAA) projections generate the low demand case. Low jet fuel prices and the FAA fuel efficiency performance targets generate the high jet fuel demand case. Staff did not attempt to project military jet fuel use, so military consumption is excluded from the forecast. Table 2.9 and Figure 2.22 show the low and high jet fuel demand cases.

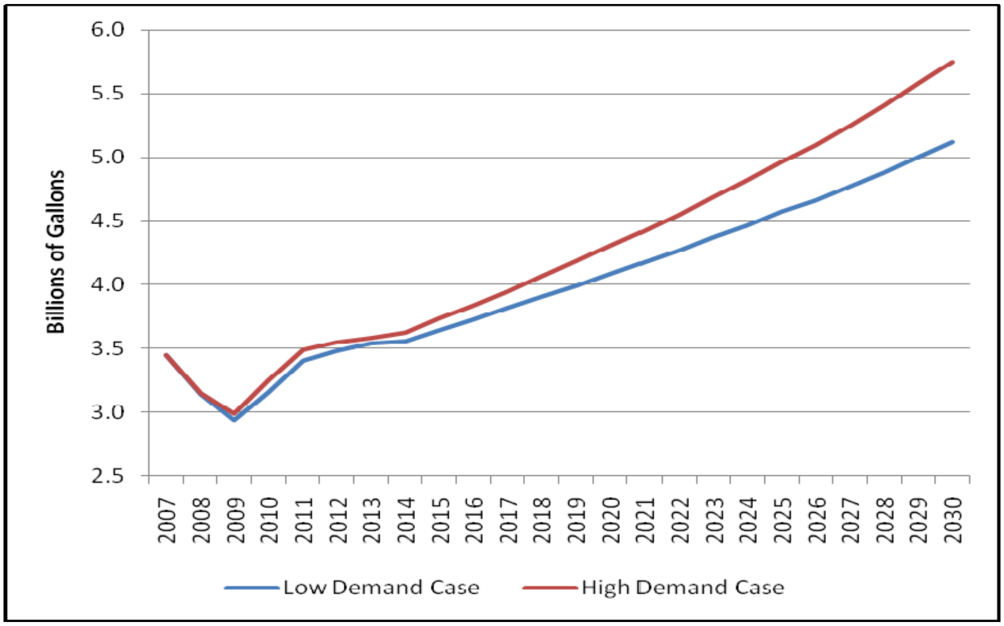
Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 51.2 percent to 5.12 billion gallons in the low demand case and 67.2 percent to 5.75 billion gallons in the high demand case.

Table 2.9: California Jet Fuel Demand Forecast (Gallons)

Year	Low Demand Case	Change from Previous Value	High Demand Case	Change from Previous Value
2007	3,446,593,006		3,446,593,006	
2010	3,156,383,966	-8.42%	3,247,229,634	-5.78%
2015	3,641,014,703	15.35%	3,733,969,879	14.99%
2020	4,081,988,183	12.11%	4,302,667,349	15.23%
2025	4,569,339,667	11.94%	4,964,917,236	15.39%
2030	5,115,783,871	11.96%	5,748,285,636	15.78%
Average Annual Growth Rate	1.73%		2.25%	

Source: California Energy Commission

Figure 2.22: California Jet Fuel Demand Forecast



Source: California Energy Commission

CHAPTER 3: 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 that have yet to be addressed regarding adequacy of both additional supplies and the requisite infrastructure to receive and distribute increased quantities of ethanol and biodiesel to California consumers. In some circumstances, different federal and state policies may result in counteracting trends that could imperil attainment of their stated goals. 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 provide historical information, regulatory context, supply assessments, and identification of infrastructure barriers that could endanger adequacy of transportation fuel supplies for California motorists and businesses. Available time and resources dictate that staff focuses on those issues that appear to have the most pressing near-term consequences, namely the intersection of complex state and federal renewable fuel rules that prescribe percentages and volumes of renewable fuels consumed, particularly ethanol. Other fuels will be discussed, but with the understanding that the time, dialogue, and research needed to fully quantify their contributions to petroleum and carbon reduction, and the barriers to their adoption, are limited. However, staff is committed to developing these analyses in future work as resources and time permit and seeks an open and ongoing discussion with stakeholders to work to that end.

Key Questions

Renewable Fuels

How much additional ethanol and biodiesel will be required in California over the next several years?

Is there enough domestic production capacity available to meet this increase in renewable fuel demand?

When will ethanol demand in California exceed the ethanol “blend wall” of 10 percent by volume?

Can California move to a 15 percent ethanol limit in gasoline over the near to mid-term?

If not, what type of E85 infrastructure (vehicles and retail outlets) and timing would be required to accommodate ethanol volumes above the blend wall?

Will the LCFS necessitate a change in the type of ethanol required to achieve compliance with the new standard?

What will be the source of this other type of ethanol, and will there be enough supply available to meet California's estimated demand?

If so, what type of infrastructure would be needed, and is that import capacity currently in place?

If not, how much time would be required to construct new capabilities and modify existing infrastructure in time to meet anticipated changes?

Will substantial increases in demand for ethanol place an undue burden on agriculture?

Other Alternative Fuels

How much natural gas, electricity, and hydrogen will be required to power natural gas-powered vehicles, full electric and plug-in hybrid electric vehicles, and fuel cell vehicles in California over the mid- to long-term future? Are these energy sources going to be available in sufficient supply and at a price attractive to consumers?

What are the barriers to increased use of natural gas, electricity, and hydrogen in transportation applications?

What is required to stimulate the production and sale of increasing numbers of natural gas, electric, and fuel cell vehicles?

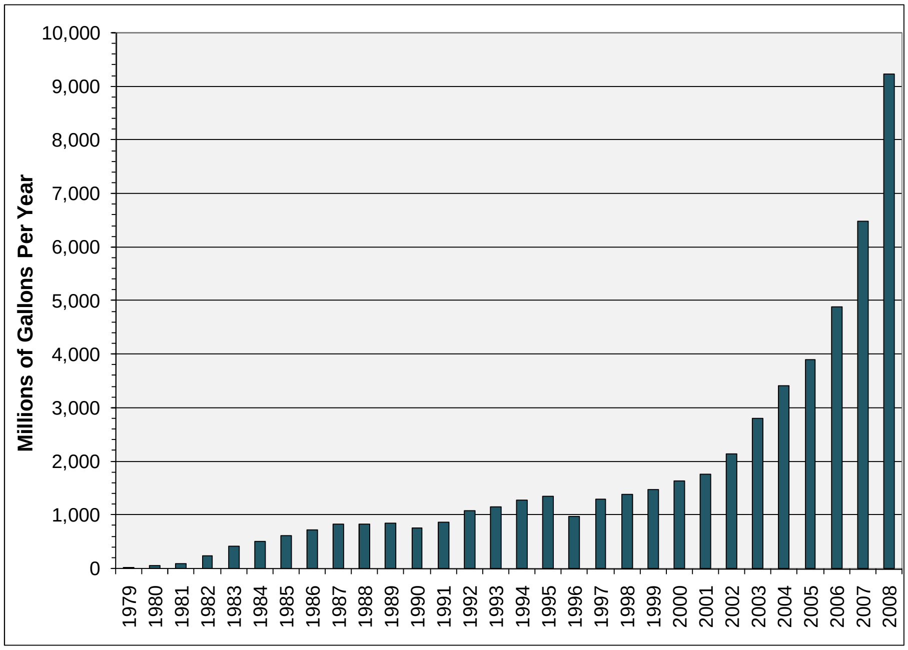
What are the options for retail refueling infrastructure needed to meet alternative fuel demand and how can the development of additional refueling facilities be stimulated? What are the options for home refueling of natural gas and electric vehicles, and what steps are needed to promote their adoption?

What standards, specifications, and other technical conventions need to be developed to promote alternative fuel vehicle sales and energy use?

Ethanol Overview

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.[15] 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 1970s spurred government action and intervention.[16] Federal assistance in the form of tax credits and loan guarantees resulted in a resurgence of the U.S. ethanol industry from "practically zero" in 1978 to more than 210 million gallons by 1982.[17,18] Figure 3.1 shows the annual progression of ethanol production in the United States between 1979 through 2008.

Figure 3.1: U.S. Ethanol Production 1979-2008



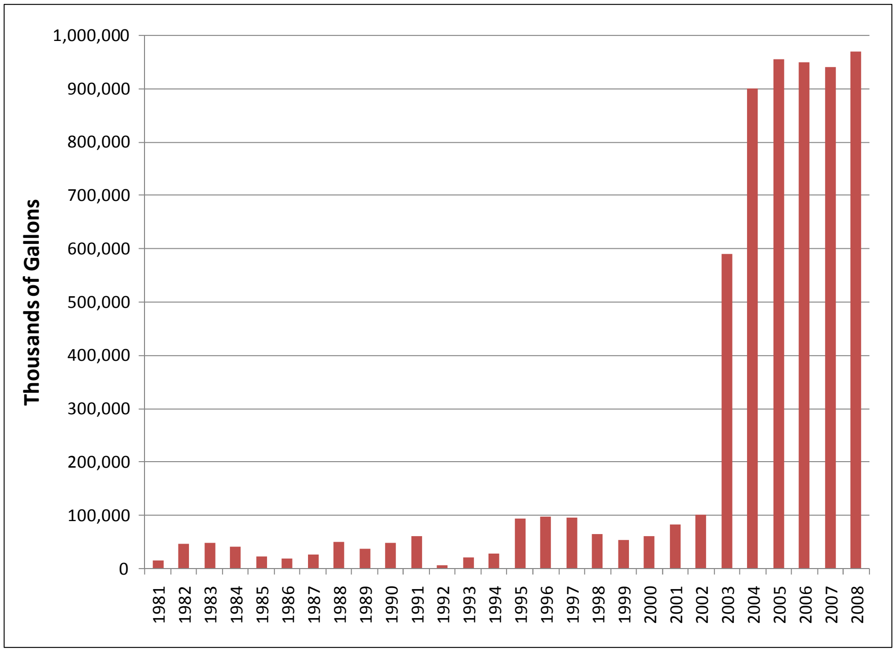
Sources: U.S. Department of Agriculture (USDA) and the Energy Information Administration (EIA).

Beginning in 1980, ethanol's use for blending in gasoline at concentrations of 10 percent by volume (referred to as gasohol or E10) 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 administered by the U.S. EPA.[19] Beginning in January 1995, federal reformulated gasoline regulations took effect that required year-round use of oxygenates in roughly one-third of the nation's gasoline.[20] ARB adopted reformulated gasoline regulations specific to the state that required all gasoline sales to meet the new standard beginning March 1, 1996.[21] Oxygenates for these federal and state programs included ethers (such as MTBE and 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.

The phase-out of MTBE (due to ground water contamination concerns) and passage of the RFS are the most recent 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 of eliminate its use due to concerns of potential widespread contamination of drinking water sources.[22] 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 oxygenate left standing.[23] Figure 3.2 depicts the estimates fuel ethanol consumption in California between 1981 and 2008. Demand for ethanol rapidly increased in 2003 as a number of refiners elected to transition away from MTBE earlier than the revised deadline of December 31,

2003. Once the MTBE phase-out was completed in 2004, ethanol demand jumped again before stabilizing just short of one billion gallons per year.

Figure 3.2: California Ethanol Demand 1981-2008



Sources: U.S. Federal Highway Administration (FHA), California State Board of Equalization (BOE) and Energy Commission analysis.

Congress took additional steps to expand 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 the Energy Independence and Security Act of 2007 (EISA). The following section describes the recent proposed RFS modifications and their implications for mandated minimum renewable fuel volumes for the United States and California.

Renewable Fuels Standard – Increased Demand for Ethanol and Biodiesel

As required by EISA, the RFS program will be altered to require the sale of 30 billion gallons of renewable fuels by 2020 and 36 billion gallons by 2022.[24] These requirements will require a substantial change to the transportation fuel market place and the ways to meet these mandates are still being considered by U.S. EPA as it continues accepting comments on its Notice of Proposed Rulemaking (NOPR) until September 25, 2009.[25] The primary change impacting renewable fuel use is the mandated use of ever-increasing quantities of biofuels, predominantly ethanol. Further, the RFS2 will require all obligated parties (refiners, importers, and blenders) to achieve minimum renewable fuel use each year either through actual use (blending) or purchase of RIN credits from other market participants who blended a greater quantity of renewable fuel than was required by the RFS2 requirements. Refiners and importers are required to determine their Renewable Volume Obligation (RVO) each calendar year that is calculated from the RFS percentage assigned by the U.S. EPA during November of the preceding year.[26] For 2009, the RFS obligation is 10.21 percent and assumes that 11.1 billion gallons of renewable fuel will be blended into gasoline and diesel fuel. Beginning in 2010, these obligations will include "fair share" blending of four different categories of renewable fuels through actual use or purchase of appropriate RINs.[27] The annual nationwide requirements are listed in Table 3.1.

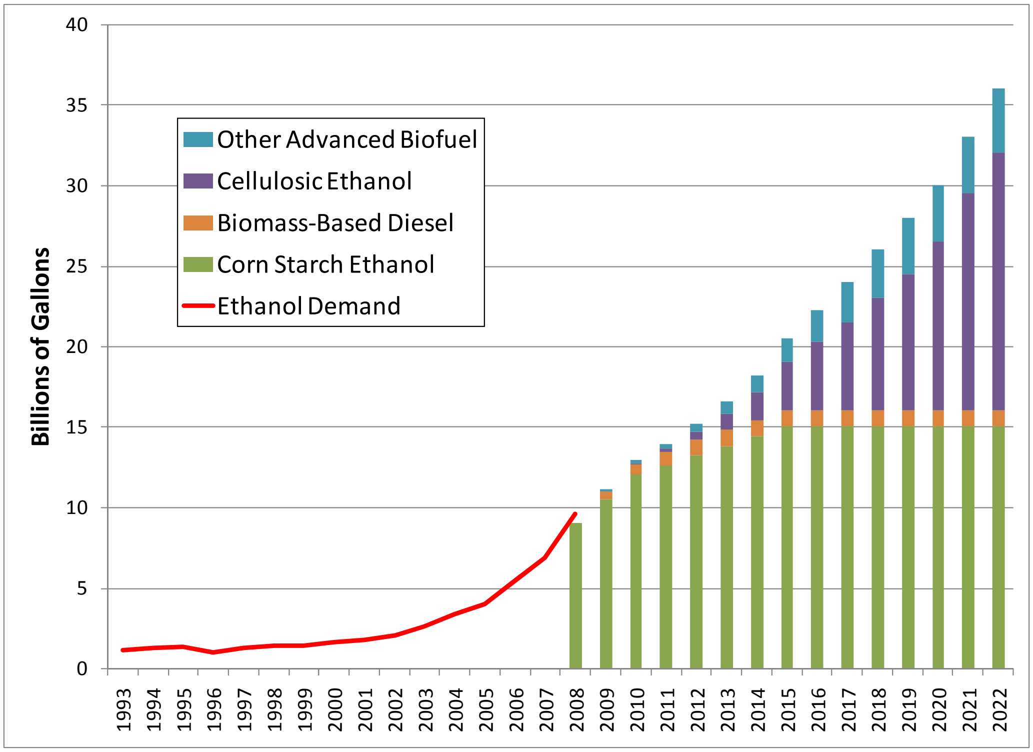
Table 3.1: U.S. RFS2 Requirements 2008-2022

			Advanced Biofuels			
Year	Total Renewable Fuel Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	9.00	9.00				0.00
2009	11.10	10.50		0.10	0.50	0.60
2010	12.95	12.00	0.10	0.20	0.65	0.95
2011	13.95	12.60	0.25	0.30	0.80	1.35
2012	15.20	13.20	0.50	0.50	1.00	2.00
2013	16.55	13.80	1.00	0.75	1.00	2.75
2014	18.15	14.40	1.75	1.00	1.00	3.75
2015	20.50	15.00	3.00	1.50	1.00	5.50
2016	22.25	15.00	4.25	2.00	1.00	7.25
2017	24.00	15.00	5.50	2.50	1.00	9.00
2018	26.00	15.00	7.00	3.00	1.00	11.00
2019	28.00	15.00	8.50	3.50	1.00	13.00
2020	30.00	15.00	10.50	3.50	1.00	15.00
2021	33.00	15.00	13.50	3.50	1.00	18.00
2022	36.00	15.00	16.00	4.00	1.00	21.00

Source: U.S. Environmental Protection Agency.

The demand for ethanol in 2008 was 9.6 billion gallons or 600 million gallons greater than the RFS requirement for last year. Figure 3-3 shows the progression of ethanol use in the United States and the RFS2 obligations through 2022. Although the estimated demand for 2009 (based on only four months of data) appears too low to achieve compliance with the minimum renewable fuel use requirements, keep in mind that excess RIN credits will likely be used by some obligated parties and that ethanol blending is expected to continue increasing throughout the remainder of 2009.

Figure 3.3: U.S. Ethanol Use and RFS Obligations 1993-2022



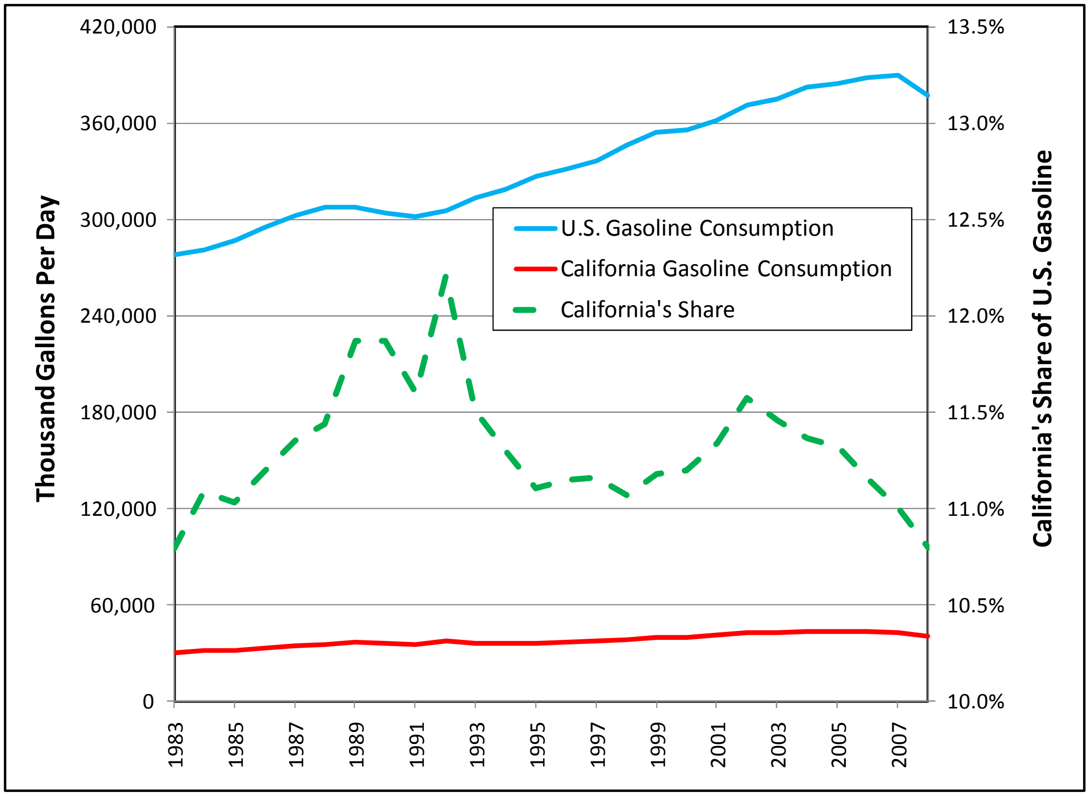
Sources: Energy Information Administration (EIA), U.S. EPA and Energy Commission analysis.

California Fair Share From RFS2

To determine what quantity of renewable fuel might be needed in California to meet compliance with the RFS2, staff had to determine what the "fair share" RFS2 obligation might be under both Low and High Demand Cases for gasoline over the forecast period. Although compliance with the RFS2 by refiners, importers, and blenders can include acquisition of RIN credits and over-compliance on a company basis in other areas of the United States outside California, for this part of the analysis, staff assumed that all obligated parties in California would be complying by blending their "fair share" of renewable fuels within the state's borders. This approach will yield more of a "worst case" infrastructure assessment but still recognizes that the forecasted demand for ethanol and biodiesel could be a bit less than presented in this report.

The first step was to figure out what the "fair share" should be for the various types of renewable fuels mandated under the proposed RFS2 standards. Staff analyzed California's gasoline demand relative to the total in the United States. Since 1983, U.S. motor gasoline use has been growing at an average annual growth rate of 0.95 percent, rising from an average consumption of 278 million gallons a day in 1983 to 377 million gallons a day in 2008.[28] California's share of U.S. gasoline consumption has fluctuated over the last 25 years and is the same percentage in 2008 as it was back in 1983 (see Figure 3-4). Between 1998 and 2008, California's share of total gasoline demand has averaged 11.2 percent. However, this percentage has been steadily declining between 2002 (11.6 percent) to 2008 (10.8 percent).

Figure 3.4: U.S. and California Motor Gasoline Consumption 1983-2008



Sources: Energy Information Administration (EIA), California BOE and Energy Commission analysis.

To meet the regulatory necessities of RFS2 over the forecast period, staff calculated California's share of gasoline demand by comparing the Energy Commission gasoline demand forecast to that of the 2009 AEO Energy Information Administration forecast that was revised in April 2009.[29] This calculated California share of gasoline demand was then applied to each of the four RFS2 renewable fuel annual minimum requirements (refer back to Table 3.1) to determine how much ethanol and biodiesel would be necessary to achieve "fair share" compliance with the RFS2. For 2023 through 2030, the RFS2 annual domestic requirements were held fixed at the 2022 levels. However, it is recognized that the EPA proposed RFS2 regulations note that values post 2022 may be adjusted and could be higher than the values used by staff in this forecast analysis. Under the Low Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,208 million gallons in 2010 to 2,108 million gallons by 2020. Under the Low Demand Case for diesel fuel, minimum biodiesel demand in California is forecast to grow from 38 million gallons in 2010 to nearly 59 million gallons by 2020 (see Table 3.2).

Table 3.2: California Renewable Fuel Requirements 2008-2030 Low Gasoline and Diesel Fuel Demand Case

Year	Total Ethanol Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels: Cellulosic Biofuels Bil. Gallons	Advanced Biofuels: Other Advanced Biofuels Bil. Gallons	Advanced Biofuels: Biomass Based Diesel Bil. Gallons	Advanced Biofuels: Total Advanced Biofuels Bil. Gallons
2008	0.974	0.974				0.000
2009	1.109	1.099		0.010	0.031	0.041
2010	1.208	1.178	0.010	0.020	0.038	0.067
2011	1.237	1.185	0.024	0.028	0.045	0.097
2012	1.305	1.213	0.046	0.046	0.056	0.148
2013	1.389	1.233	0.089	0.067	0.057	0.214
2014	1.479	1.242	0.151	0.086	0.058	0.296
2015	1.618	1.244	0.249	0.124	0.060	0.433
2016	1.701	1.201	0.340	0.160	0.059	0.559
2017	1.770	1.154	0.423	0.192	0.059	0.675
2018	1.892	1.135	0.530	0.227	0.059	0.816
2019	2.002	1.112	0.630	0.260	0.059	0.949
2020	2.108	1.091	0.763	0.254	0.059	1.077
2021	2.265	1.062	0.956	0.248	0.060	1.263
2022	2.424	1.039	1.108	0.277	0.060	1.445
2023	2.404	1.030	1.099	0.275	0.059	1.433
2024	2.379	1.019	1.087	0.272	0.059	1.418
2025	2.374	1.017	1.085	0.271	0.059	1.415
2026	2.368	1.015	1.082	0.271	0.058	1.411
2027	2.382	1.021	1.089	0.272	0.058	1.419
2028	2.375	1.018	1.086	0.271	0.058	1.415
2029	2.399	1.028	1.097	0.274	0.058	1.429
2030	2.397	1.027	1.096	0.274	0.057	1.427

Source: Energy Commission analysis

Under the High Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,245 million gallons in 2010 to 2,550 million gallons by 2020. Under the High Demand Case for diesel fuel, minimum biodiesel demand in California is forecast to grow from 37 million gallons in 2010 to nearly 61 million gallons by 2020 (Table 3.3).

Table 3.3: California Renewable Fuel Requirements 2008-2030 High Gasoline and Diesel Fuel Demand Case

Year	Total Ethanol Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels: Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	0.969	0.969				0.000
2009	1.125	1.114		0.011	0.031	0.041
2010	1.245	1.215	0.010	0.020	0.037	0.068
2011	1.318	1.263	0.025	0.030	0.044	0.099
2012	1.424	1.324	0.050	0.050	0.055	0.155
2013	1.556	1.381	0.100	0.075	0.056	0.231
2014	1.695	1.423	0.173	0.099	0.057	0.329
2015	1.906	1.466	0.293	0.147	0.059	0.499
2016	2.054	1.450	0.411	0.193	0.058	0.662
2017	2.193	1.430	0.524	0.238	0.059	0.822
2018	2.320	1.392	0.650	0.278	0.060	0.988
2019	2.429	1.350	0.765	0.315	0.060	1.140
2020	2.550	1.319	0.923	0.308	0.061	1.292
2021	2.727	1.278	1.150	0.298	0.062	1.511
2022	2.942	1.261	1.345	0.336	0.062	1.743
2023	2.939	1.260	1.344	0.336	0.062	1.742
2024	2.893	1.240	1.323	0.331	0.061	1.715
2025	2.856	1.224	1.305	0.326	0.061	1.693
2026	2.826	1.211	1.292	0.323	0.061	1.676
2027	2.786	1.194	1.274	0.318	0.060	1.652
2028	2.746	1.177	1.255	0.314	0.059	1.628
2029	2.730	1.170	1.248	0.312	0.058	1.618
2030	2.706	1.160	1.237	0.309	0.058	1.604

Source: Energy Commission analysis.

Greater use of ethanol in California could be accomplished by (1) adoption of new upper limits for low-level ethanol blends in excess of the current E10 standard, or (2) increased sales of E85 (a mixture of 15 percent gasoline and 85 percent ethanol). Experts generally recognize that there are potential vehicle operability and emission issues that need to be addressed before the low-level cap on ethanol blends in gasoline (referred to as the *blend wall*) can be increased to levels greater than 10 percent.[30]

Ethanol Blend Wall

It is estimated that ethanol demand in California will eclipse an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on gasoline demand growth rates. Original engine manufacturers (OEMs) generally have vehicle warranties that are voided if the owner uses gasoline with more than 10 percent by volume ethanol. OEMs are concerned about potential harm to the catalyst in their vehicles. A recent study conducted on behalf of the University of Minnesota, however, suggests existing vehicles could operate at slightly higher ethanol concentrations without undue operational or emissions problems.[31] The U.S. DOE is conducting vehicle testing of intermediate ethanol blends (E15 and E20) to measure effects on vehicle emissions, catalysts, and engine durability. This group has recently released a preliminary report that did not identify any significantly detrimental issues.[32] Lastly, U.S. EPA has been petitioned by Growth Energy to allow the ethanol blend wall to be increased to 15 percent by volume or E15.[33]

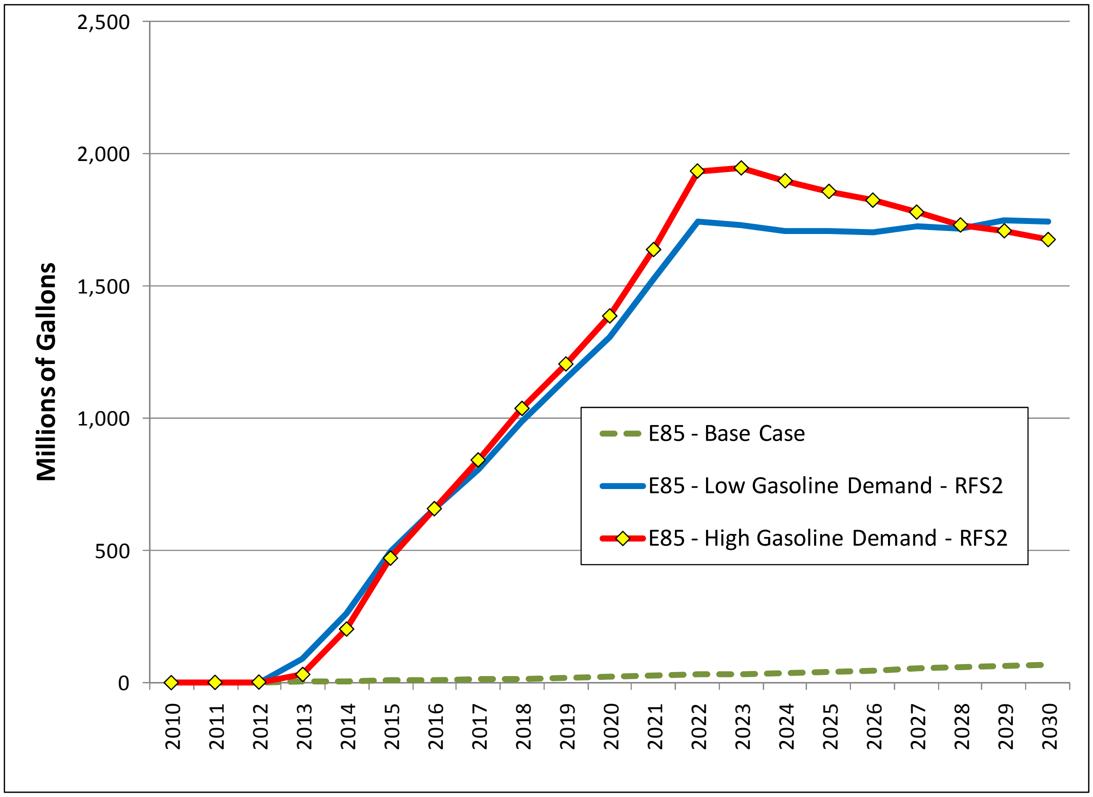
It is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume, even if the EPA ultimately grants permission for U.S. refiners and marketers to go to E15. California's revised reformulated gasoline specifications (referred to as the revised Predictive Model) go into effect on January 1, 2010. Information used to develop mathematical relationships between various gasoline properties (such as sulfur and oxygen content) and vehicle emissions (both evaporative and tailpipe) did not include gasoline with blends of ethanol greater than 10 percent by volume. As such, this ARB regulation would have to be modified before E15 blends could be considered for use in the state. Since this process would require several years to complete (if this path were to be pursued) and the outcome uncertain, staff has assumed in this analysis that E10 will remain the practical upper limit in California gasoline low-level blends over the foreseeable future.

Increased Ethanol Use in Gasoline – E85

Since the ethanol blend wall in California is assumed to remain at 10 percent by volume over the forecast period, the only reasonable means using more ethanol in transportation fuels is to increase the sales of E85. As of October 2008, there were nearly 382,000 registered vehicles in California that could use either gasoline or E85.[34] These vehicles are referred to as FFVs. Although there is a large population of FFVs in California, there are only a few retail stations that offer E85. As of July 2009, there were only 25 retail stations that offered E85 to the public. Staff expects that the quantity of E85 sold in California will increase in response to higher levels of mandated ethanol use due to the RFS2. However, the pace of this expansion may be inadequate to achieve compliance due to a variety of infrastructure challenges and disincentives.

There are several challenges to expansion of E85 sales in California. Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with RFS2 requirements. Assuming a 10 percent ethanol blend wall, E85 sales in California are forecast to rise from 2 million gallons in 2010 to 1,389 million gallons in 2020 and 1,678 million gallons by 2030 under the High Demand Case for gasoline. Figure 3.5 shows the annual E85 forecast for both the Low and High Demand Cases.

Figure 3.5: California E85 Demand Forecast 2010-2030



Source: Energy Commission analysis.

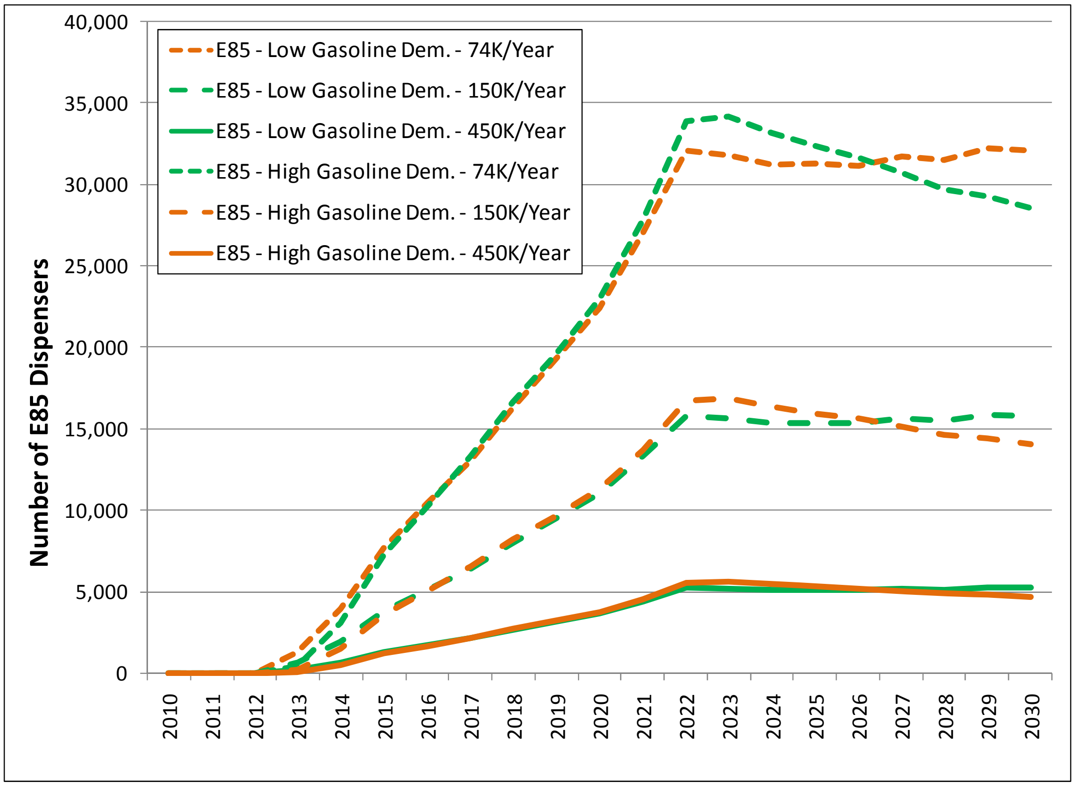
However, the proposed RFS2 regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to comply with the RFS2 standards, but retail station operators do not have any obligation. This is an apparent "disconnect" in the RFS2 policy that could easily result in a retail infrastructure that is inadequate to handle the necessary increase in E85 sales.

Another potential issue is what type of base gasoline will be necessary to blend with ethanol to produce E85? If the blendstock is something other than CARBOB for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.

To calculate the number of retail stations that would need to offer E85, staff had to first estimate the number of E85 dispensers that would need to be operating. This quantity of E85 dispensers can vary depending on the annual statewide demand for E85 and the average annual distribution of E85 per dispenser. Depending on the average quantity of fuel sold by a typical E85 dispenser, California could require between 3,000 and 19,000 E85 dispensers by 2020. The average annual distribution of transportation fuel per fuel dispenser in California between July

1, 2007, and June 30, 2008, is estimated at 452,000 gallons. However, staff estimates that a dispenser that sells only one type of fuel sold an average of between 150,000 and 175,000 gallons over this same period.[35] Actual per-station E85 annual sales figures for Minnesota are much lower, averaging about 74,000 gallons.[36] The impact of lower annual throughput and minimum per-gallon margins necessary to make a profit are discussed later in this section. Figure 3-6 depicts the growth in E85 dispenser availability over the forecast period that would be necessary to distribute sufficient volumes of E85 to help meet comply with the RFS2.

Figure 3.6: California E85 Dispenser Forecast 2010-2030



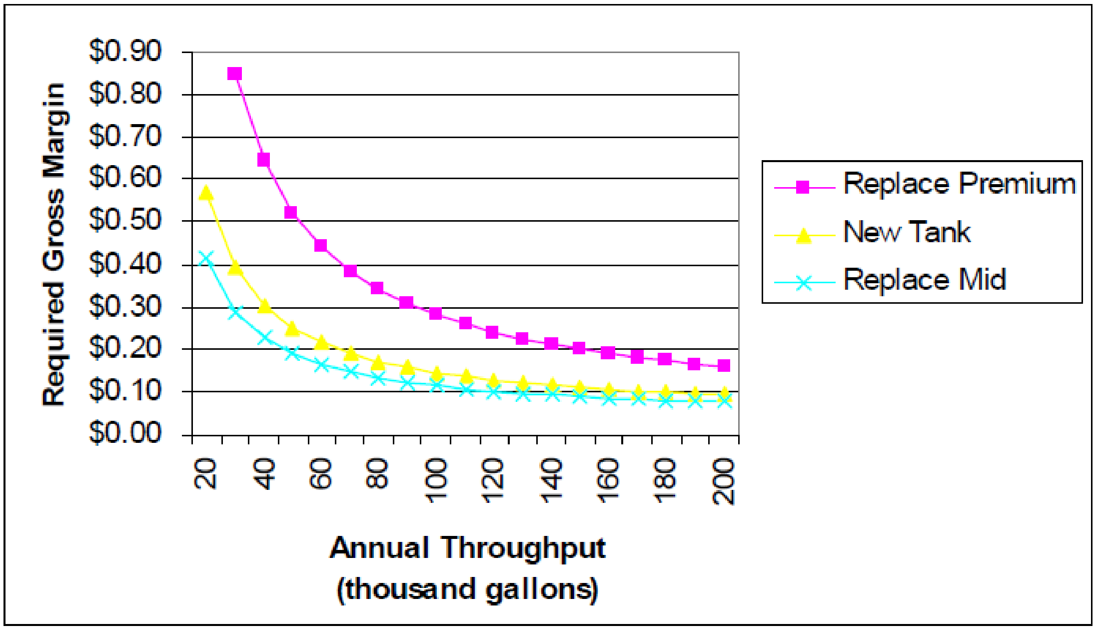
Source: Energy Commission analysis.

The significant increase in E85 dispenser availability at California retail stations has a potential barrier or increased difficulty associated with equipment approval. Most (if not all) retail dispensers have been certified by Underwriters Laboratories (UL) or are assembled using UL-approved parts and components. During October 2006, UL "suspended authorization for manufacturers to use UL markings (Listing or Recognition) on components for fuel-dispensing devices that specifically reference compatibility with alcohol-blended fuels that contain greater than 15 percent alcohol i.e., ethanol, methanol or other alcohols."[37] UL announced during October 2007 that it had developed procedures for reviewing dispensers suitable for selling E85.[38] This step means that manufacturers may submit components intended for use in E85 dispensers for UL certification. It is not known how many dispensers designed for dispensing E85 have been certified by UL, if any.[39] Furthermore, it is uncertain how this situation may or may not be impeding installation of E85 dispensers in California since several new retail locations have starting selling E85 over the last several months. It is possible that variances or waivers are being granted for E85 equipment submitted for approval by local jurisdiction that has oversight.

E85 retail infrastructure is expensive. Costs for installing a new UST, dispenser, and appurtenances range between $50,000 and $200,000.[40] Costs can be reduced if an existing UST is used to store and dispense the E85. Dedicated mid-grade and premium storage tanks are two examples, although each option has additional complications. The mid-grade replacement option is estimated to cost only $20,000 but requires a station that has a dedicated mid-grade gasoline tank.[41] The portion of retail stations in California that still have dedicated mid-grade USTs is estimated at no more than 30 percent.[42] This option in California is limited and will decline in the future since new retail stations do not normally install a dedicated mid-grade UST. The National Renewable Energy Laboratory (NREL) also examined a scenario whereby a retail station owner uses a dedicated premium grade gasoline UST to store and dispense E85. This option will likely eliminate premium and mid-grade gasoline sales at a retail station. It should also be noted that premium grade gasoline sales usually command the highest profit margin. A retail station owner would have to believe that the E85 margins would be even higher when compared to premium gasoline for this business strategy to be a viable option.

NREL conducted modeling to assess various factors that can impact profitability of a decision to modify an existing retail station to dispense E85. Figure 3.7 shows the three options (new tank, use of existing mid-grade tank, and use of existing premium tank) and the per-gallon level of margin required to sustain profitability over a wide range of annual E85 fuel throughput. The graph illustrates that the new tank and mid-grade tank options are similar, while the premium option requires higher margins at any level of throughput.

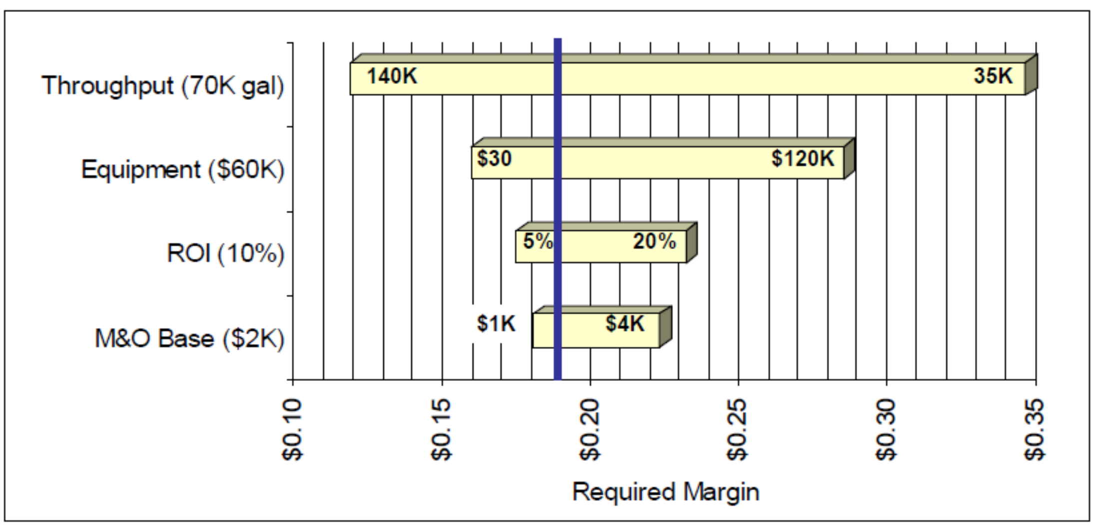
Figure 3.7: E85 Business Scenario Margins and Annual Throughput



Sources: NREL Technical Report TP-540-41590, Dec. 2007, Figure 5, page 13.

The actual level of E85 sales is probably the most important variable for determining the per-gallon margin necessary to be profitable. Variation in the actual cost of equipment is the second most important variable. Figure 3.8 shows how the level of margin required to be profitable changes as the various factors are adjusted upward or downward.

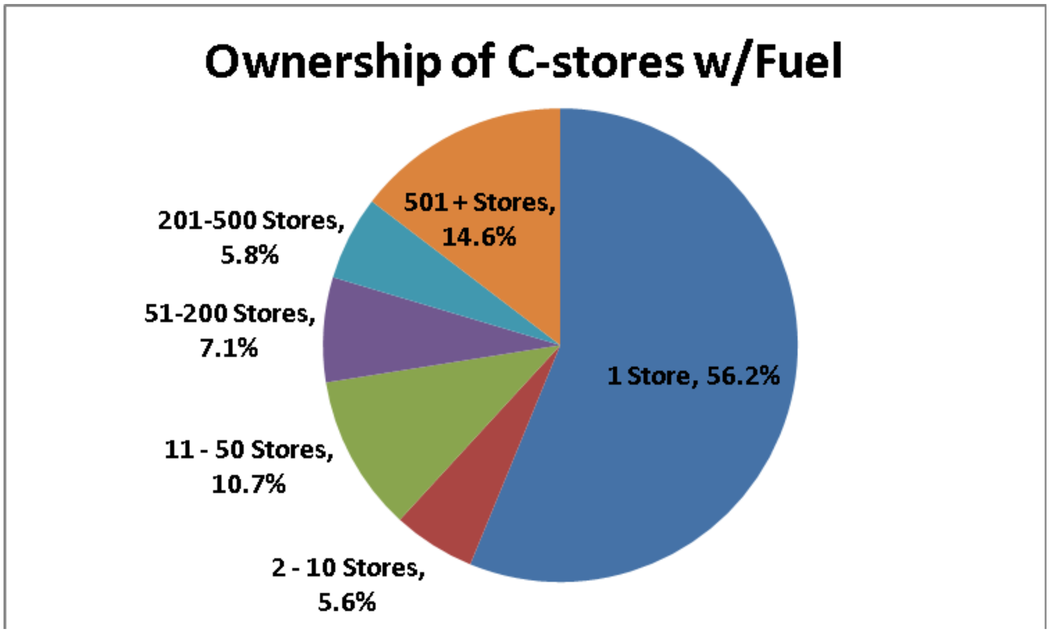
Figure 3.8: E85 New Tank Scenario Factors and Required Margin



Sources: NREL Technical Report TP-540-41590, Dec. 2007, Figure 6, page 15.

Most retail station owners and operators could have a difficult time obtaining sufficient resources to finance this type of work. Nearly 60 percent of retail stations in the United States are owned and operated by someone who has one store (see Figure 3-9).[43] Large oil companies are actually reducing the number of retail stations they own and operate.

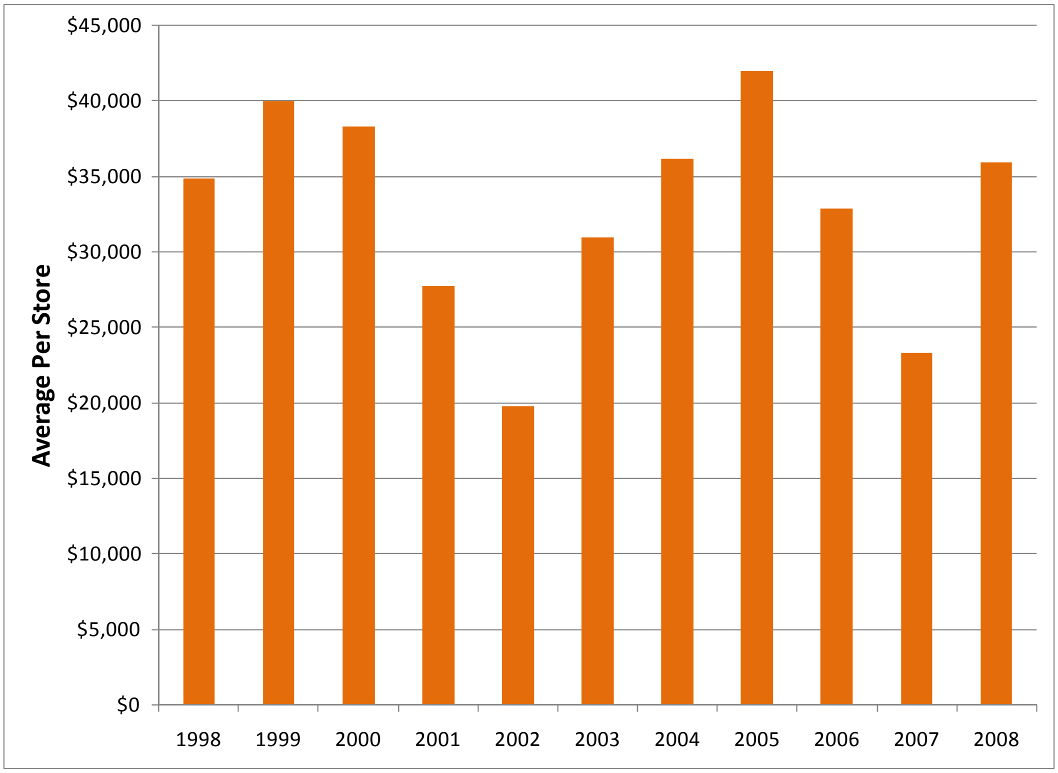
Figure 3.9: U.S. Convenience Store Ownership Profile



Sources: National Association of Convenience Stores (NACS) and TDLinx Official Industry Store Count, Feb. 2009.

Once again, there is no obligation to install E85 dispensers nor is there a strong financial incentive for a typical retail station owner. During 2008, more than 80 percent of the gasoline sold to the public nationwide was through convenience stores.[44] These places of business have continued to be profitable over the last decade, averaging nearly $32,700 per store pre-tax profits between 1999 and 2008.[45] Figure 3.10 shows that these pre-tax profits are not steady but can fluctuate over time. It is possible that because most stations are operated by a sole proprietor and pre-tax profits are historically less than $40,000 per year, voluntary installation of a new E85 retail dispenser, UST, and associated piping is a business proposition that would be difficult to justify. In fact, the majority of retail locations that have recently installed E85 dispensers in California have done so with either partial or complete financial assistance from other funding sources.[46]

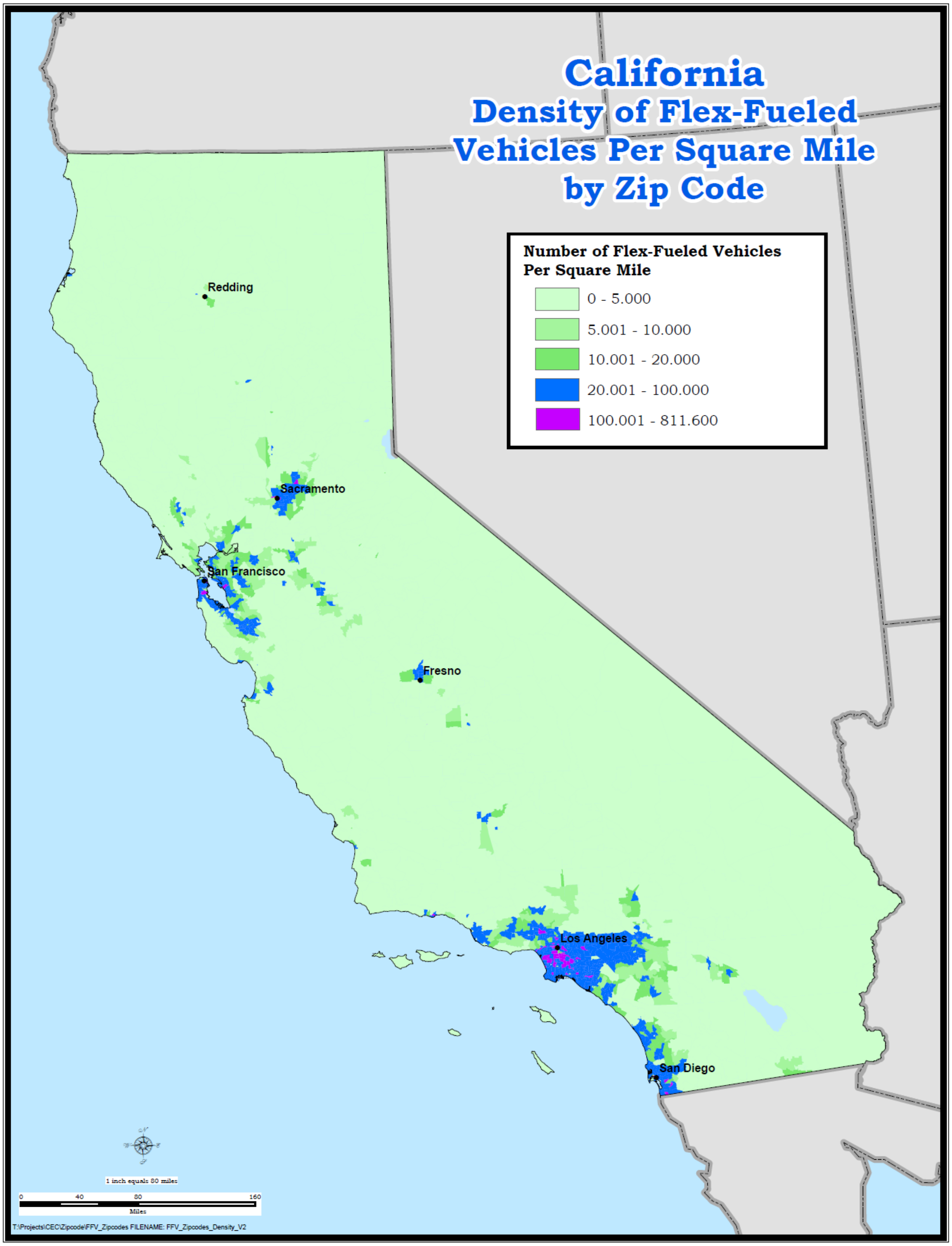
Figure 3.10: U.S. Convenience Store Average Pre-Tax Profits 1998-2008



Sources: NACS State of the Industry Report data and 2009 press release.

However, the state should continue to provide as much assistance as available resources permit to help increase the likelihood of successful E85 availability. One such example could be the periodic publication of FFV ownership density maps that show which locations (by ZIP code divisions) have the highest concentration of FFVs so that retail station owners and other business interests can initially target locations that have a greater number of FFVs. Figure 3.11 depicts the FFV density for California for April 2008. The darker areas have the greatest density of FFVs per geographic area, while the lightest shading has the lowest concentration.

Figure 3.11: California FFV Density Map – 2007

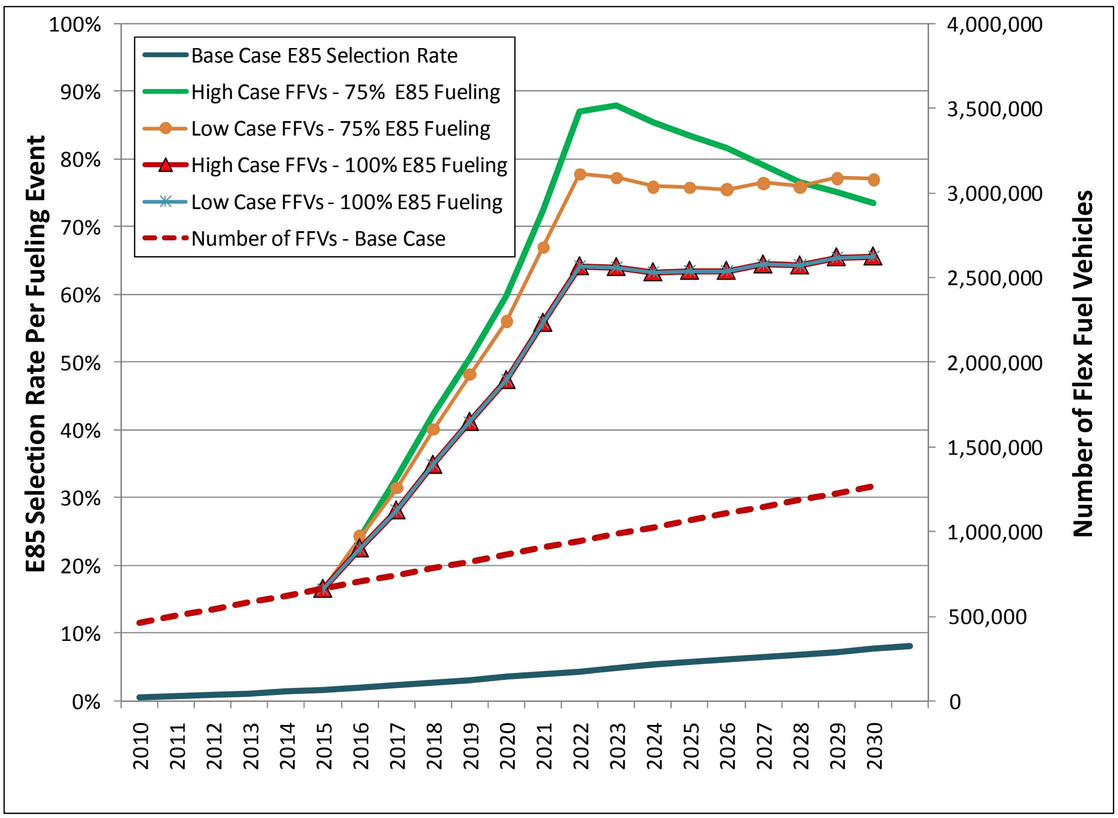


Sources: California Department of Motor Vehicle (DMV) data and Energy Commission analysis.

E85 Demand and Flexible Fuel Vehicle Forecast

Along with the forecast rise of E85 sales in California, there is a commensurate rise in the number of FFVs that would be necessary to use greater volumes of E85. The FFV forecast depends on the total demand for E85, the fuel economy of FFVs, the average number of vehicle miles traveled (VMT) per FFV, and the frequency of E85 fueling by a typical FFV owner. Based on these interrelated factors, the FFV population would need to grow from a total of 382,000 vehicles in October 2008 to as many as 2.4 million FFVs by 2020 and 3.3 million by 2025. Figure 3.12 shows the FFV forecast for both the Low E85 and High E85 Demand Cases. The lower FFV forecasts assume that FFV owners elect to use E85 each fueling event (100 percent of the time). Even higher numbers of FFVs would be required if owners fueled with E85 at least 75 percent of the time.

Figure 3.12: California FFV Demand Forecast 2010-2030



Source: Energy Commission analysis

Based on these FFV forecast trends, a significantly greater number of FFVs will need to be sold in California than are assumed in the base case as soon as 2015. Most automakers are believed to having committed to produce up to half of their new vehicle models as FFV-compliant by 2012, contingent upon an adequate fueling infrastructure.[47] However, the ability of automobile manufacturers to produce an even greater portion of their new models as FFVs for sale in California could be challenged due to increasingly stringent emission standards and higher fuel economy standards.

Flexible Fuel Vehicles – Technical and Policy Challenges

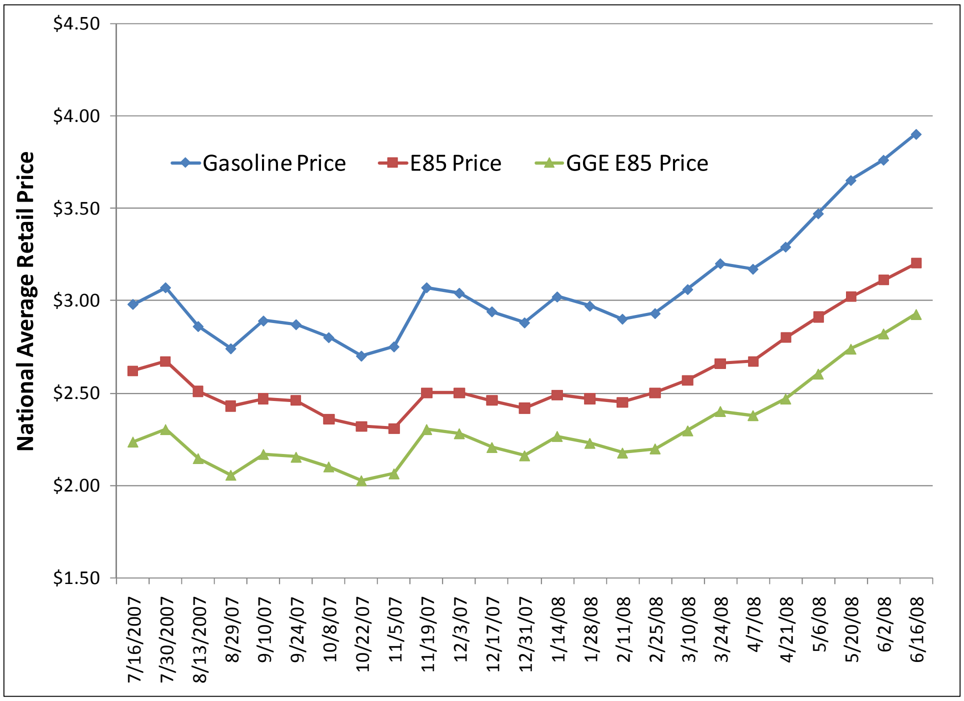
New vehicles offered for sale in California have to include an increasing percentage of models that meet super–ultra-low-emission vehicle (SULEV) and PZEV evaporative emission standards. Compliance with these standards is a technical challenge for FFVs.[48] These technical challenges are currently limiting the number of new vehicles that can be offered for sale as FFVs.[49] Regulations adopted by ARB designed to reduce emissions from new vehicle models (both tailpipe and evaporative), along with revised ZEV standards, will require automobile manufacturer compliance with more stringent emission standards and growing percentage of ZEV and PZEV sales.[50] Both of these sets of standards will create significant challenges for greater introduction of FFVs. The upper limit of FFV availability for new vehicle sales and incremental cost of California vehicle emission standards is unknown at this time.

Increasing fuel economy standards will require vehicle manufacturers to offer for sale a mixture of makes and models that will meet the more stringent corporate average fuel economy (CAFE) goals. The granting of California's waiver request by U.S. EPA on June 30, 2009, has allowed for the setting of limits on the GHG emissions from new vehicle sales in this state.[51] One potential implication of this regulation is that the mix of new vehicles offered for sale in California will need to achieve ever-higher CAFE standards. As such, vehicle manufacturers may plan to offer certain makes and models of more fuel efficient vehicles, such as: PHEV, fuel cell, direct injection diesel, and electric vehicles. None of these vehicles are FFVs. It is possible that vehicle manufacturer marketing decisions might preclude FFVs, setting the stage for a potential shortfall of new FFV vehicle availability in California in sufficient numbers to help meet compliance with the RFS2 renewable fuel obligations. This potential policy conflict should be examined in greater detail to determine if a potential FFV availability shortfall could occur.

E85 Pricing Issues

A growing market for E85 necessitated by ever-increasing mandated use of ethanol will need to adjust to the fact that E85 has less energy per gallon when compared to a gallon of E10. This energy difference can reduce the number of miles traveled per gallon from between 23 and 28 percent.[52] As such, the retail price of a gallon of E85 would need to be an equivalent percentage less than a retail gallon of E10 to ensure that an FFV operator would receive a gallon of equal value. For example, if a gallon of E10 was priced at $2.50, a gallon of E85 would need to be priced at between $1.80 and $1.95. However, in actual practice, FFV motorists have been consistently overpaying for E85 fuel.[53] Figure 3.13 tracks the national average retail prices from this study for both gasoline and E85. Staff has also included a gasoline-gallon equivalent (GGE) price for E85 based on an average fuel economy difference of 75 percent. As the chart indicates, consumers were paying more per gallon for E85 than fuel economy equivalent price. Consumers appear to have overpaid by an average of 29 cents per gallon during the study timeframe. The overpayment ranged between 20 and 39 cents per gallon.

Figure 3.13: U.S. Gasoline and E85 Retail Prices July 2007 – June 2008



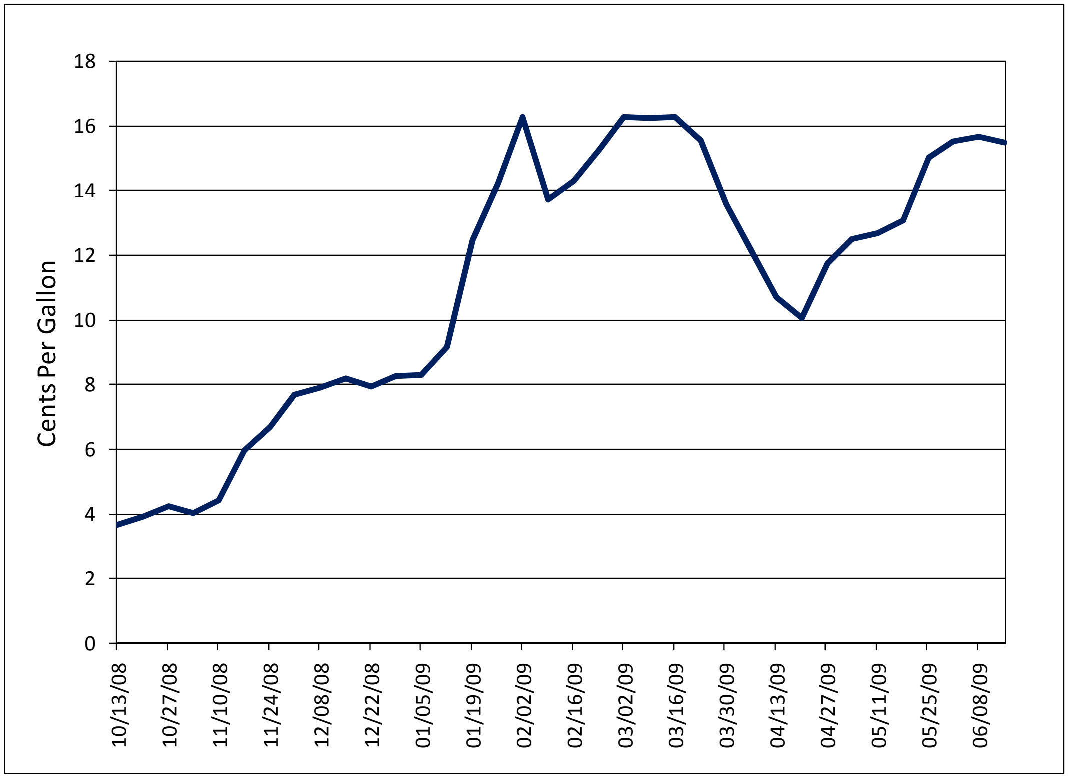
Source: National Renewable Energy Laboratory, Technical Report NREL/TP-540-44254, October 2008.

As California sales of E85 increase, there should be steps taken to help ensure that FFV motorists are receiving adequate pricing information at retail stations to put them in a position of making more informed fuel purchase decisions. Over time, FFV consumers may elect, on average, to pay a premium for E85 above the gasoline gallon equivalent (GGE) price. However, the California Division of Measurement Standards (DMS) should expand their posted retail price standards to include some form of energy-equivalent or fuel economy-equivalent pricing information at all retail stations offering E85 in California.

The lower fuel economy of E85 and resulting need to discount the price of this fuel to attract a sufficient level of demand implies that the suppliers of ethanol will need to consistently discount the wholesale price of E85. The need to provide consistently discounted ethanol for E85 blending could place downward pressure on ethanol wholesale prices and further depress ethanol producer profitability. This is one of the reasons that several ethanol producer stakeholders are pushing to have the ethanol blend wall increased from 10 to 15 percent by volume so that ethanol can be sold at or near gasoline values rather than being discounted. It should be noted that in a non-mandated market setting, E85 retail stations and availability of FFVs allow for a type of ethanol pricing "floor," meaning that as the discount between ethanol and gasoline increases, the economic incentive to blend additional volume of E85 on a discretionary basis rises allowing a greater quantity of ethanol to be sold into the fuel market (higher demand for ethanol producers). However, this discretionary market scenario will likely not develop as E85 sales in California will need to increase significantly to maintain compliance with mandated RFS2 "fair share" blending requirements.

The only possible exception to this outlook is the potential economic benefit of excess RINs.[54] The RFS2 program requires the tracking of renewable fuel use such that all obligated parties are able to verify compliance through sufficient levels of renewable fuel use or the acquisition of excess RIN credits from other market participants who have exceeded their "fair share" blending levels. Excess RIN credits have an economic value that has fluctuated between 3.7 and 16.3 cents per gallon (CPG) between October 2008 and June 2009 (see Figure 3-14). RIN values have averaged 13.6 CPG for the first half of 2009. However, these RIN credit levels may not be sufficient to overcome the economic value of the fuel economy differential (44 to 56 CPG for $2.00 gasoline), even if one assumes that the blenders receiving the RIN credit revenue will be willing to pass some of that money back through to ethanol producers in the form of higher wholesale ethanol prices.

Figure 3.14: RIN Values October 2008 – June 2009



Source: Oil Price Information Service (OPIS).

It is clear from recent history that excess RIN credits can be viewed by the holder as an additional revenue stream that can be used to help offset costs and maintain sufficient profit levels. However, the party who holds title to the RINs can be unclear, and this uncertainty complicates compliance strategies for various parties.[55] E85 blending in California is currently a practice involving other marketers who are not refiners. In this circumstance, the non-refiner blender can accrue RIN credits and their associated economic value that can be sold to either RIN aggregators, refiners, or other obligated parties. As California transitions to increased sales of E85 necessitated by RFS2, an imbalance between refiners' ethanol blending obligations and actual ethanol blending could widen if other market participants are the entities primarily blending and delivering the E85 to retail. Under this scenario, refiners would need to purchase an increasingly greater number of excess RIN credits to ensure compliance. In fact, the RINs embodied in the E85 could also be passed along to the retailer, who has no obligation to blend ethanol. Either way, it is likely that the cost of acquiring these RIN credits will be passed along to consumers in the form of higher prices over the longterm by those parties forced to acquire excess credits (such as refiners).

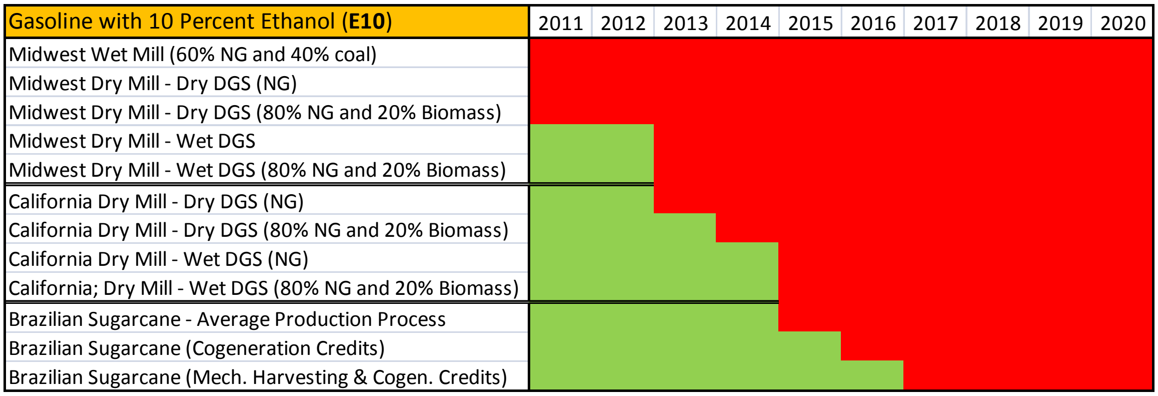
LCFS and Changing Mix of Renewable Fuel Types

The ARB adopted the LCFS regulations on April 23, 2009. The regulation is intended to reduce the per gallon carbon intensity (as measured by both direct and indirect life cycle carbon emissions) of gasoline and diesel fuel by 10 percent between 2010 and 2020.[56] The LCFS is expected to necessitate changes in the type of ethanol blended in California. Traditional ethanol (corn-based ethanol from the Midwest) has an average carbon intensity that is slightly higher than that of the base gasoline used to blend with the ethanol (referred to as CARBOB). As such, it is likely that this type of ethanol (currently supplying nearly 100 percent of California's needs) will fall from favor as early as 2011 (the first year for LCFS compliance). Therefore, other types of ethanol that have lower carbon intensity values will probably become more desirable as refiners and other obligated parties strive to achieve compliance with the RFS2 and LCFS simultaneously. Although the carbon intensity reductions appear modest, the anticipated trend of shifting from one type of ethanol to others will create potential supply and logistical challenges that could be difficult to overcome and probably result in higher compliance costs that will be passed along to consumers.

As is the case with gasoline, the lower per-gallon carbon intensity requirements of diesel fuel are expected to necessitate greater use of biodiesel to levels higher than the "fair share" biodiesel obligations associated with the RFS2. The magnitude of this increased use of biodiesel is not yet quantified since the carbon intensity values of various types of biodiesel fuels have yet to be finalized. The Energy Commission will continue to assess potential biodiesel supply and infrastructure issues as new information becomes available.

Assuming that there are no credits available from over-compliance and purchase of alternative vehicle credits, staff estimates that the LCFS for gasoline will greatly increase demand for Brazilian ethanol over the near to mid-term, while also necessitating expanded use of E85. Assuming also that the ethanol blend wall in California remains at 10 percent by volume over the forecast period, staff estimates that various types of ethanol will have limited use as a blend in E10. The lower the carbon intensity of ethanol, the longer it will be used as a blend in E10. Table 3.4 depicts the various types of ethanol and how long they can be used absent over-compliance and acquisition of offsetting credits.

Table 3.4: LCFS – Complying E10 Blends



Sources: California Air Resources Board (ARB) and Energy Commission analysis.

Based on the information in the above table, certain types of ethanol are increasing difficult to blend in gasoline as E10 without acquisition of LCFS credits (from low-carbon vehicles) or over compliance. Brazilian ethanol may be blended in E10 for several years (up through 2016) without carbon credit offsets. California ethanol is viable in E10 blends for up to four years before it would need to be exported for use outside California or blended as E85. Finally, Midwest ethanol blending would be most limited, only able to be blended for a couple of years assuming the ethanol plant had wet DGS as a co-product. Lastly, early use of Brazilian ethanol can enable a smaller portion of Midwest ethanol to be used for a longer period in E10 blends. However, the ratio of Midwest-to-Brazil ethanol declines to zero by 2017.

Since refiners and other obligated parties still need to achieve compliance with RFS2 “fair share” renewable fuel use, companies will need to examine other options for ethanol use in California besides blending with gasoline at a concentration of 10 percent by volume (E10). Increasing the concentration of ethanol in gasoline can reduce the overall carbon intensity of the blended gallon as long as the ethanol being used has lower carbon intensity than the base gasoline. Increasing use of E85 allows obligated parties to use various types of ethanol over a longer period. Table 3.5 shows the additional number of years that specific sources of ethanol can be used in a gallon of E85 for reducing the gasoline carbon intensity.

Table 3.5: LCFS – Complying E85 Blends

Gasoline with 85 Percent Ethanol (**E85**)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Midwest Wet Mill (60% NG and 40% coal)										
Midwest Dry Mill - Dry DGS (NG)										
Midwest Dry Mill - Dry DGS (80% NG and 20% Biomass)										
Midwest Dry Mill - Wet DGS										
Midwest Dry Mill - Wet DGS (80% NG and 20% Biomass)										
California Dry Mill - Dry DGS (NG)										
California Dry Mill - Dry DGS (80% NG and 20% Biomass)										
California Dry Mill - Wet DGS (NG)										
California; Dry Mill - Wet DGS (80% NG and 20% Biomass)										
Brazilian Sugarcane - Average Production Process										
Brazilian Sugarcane (Cogeneration Credits)										
Brazilian Sugarcane (Mech. Harvesting & Cogen. Credits)										

Sources: California Air Resources Board (ARB) and Energy Commission analysis.

As the table indicates, blending ethanol in E85 (under most circumstances) can achieve full per-gallon compliance with the LCFS without the need for any offsetting carbon credits. The only exceptions are California ethanol facilities that have dry DGS co-products and certain sources of Midwest ethanol.

In future years, the decreasing per gallon carbon intensity requirements for gasoline will necessitate using types of ethanol with ever-lower carbon intensities. Currently, Brazilian sugarcane ethanol has the lowest carbon life-cycle rating of all of the different types of ethanol that are currently being produced at commercial-sized facilities.[57] Lower-carbon intensity pathways for Brazilian ethanol production that employ reduced field residue burning or increased cogeneration from bagasse could achieve LCFS compliance over a longer period. The demand for this type of ethanol is expected to be strong as refiners and other market participants work toward compliance with the gasoline LCFS. As such, the quantity of ethanol that may be available from Brazil for import into California over the near term is of great importance but associated with significant uncertainty.

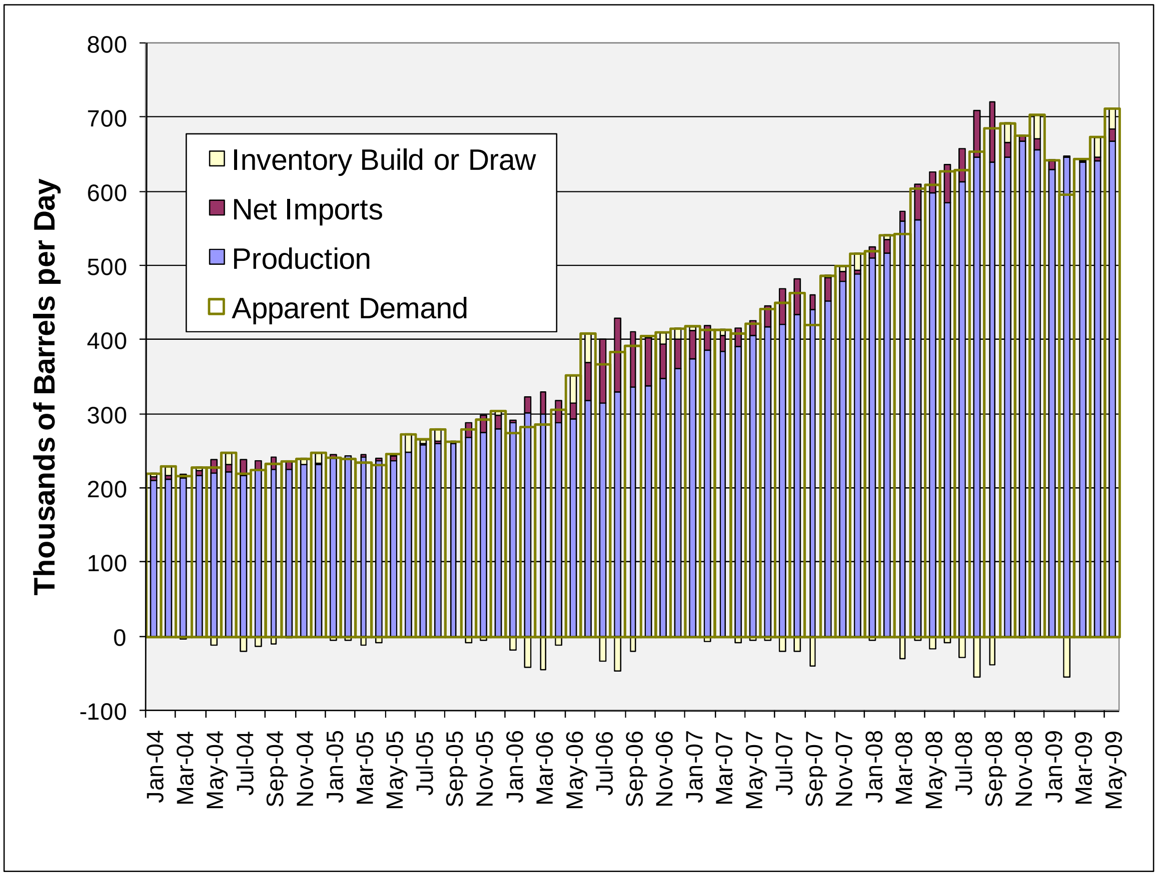
Additional pathways with lower carbon intensities can extend the length of time that ethanol can be used in gasoline blends for either E10 or E85. Verification of lower carbon intensity (CI) pathways is expected to continue over the next couple of years. This is especially the case once cellulosic ethanol and diesel fuel production is achieved and verified on a commercial scale. However, lack of information at this time precludes any analysis as to how beneficial those improvements could be to helping achieve LCFS compliance. Other "non-fuel" LCFS compliance options, such as purchase of vehicle credits, can also extend the use of ethanol in gasoline blends or reduce the need for expanded E85 use.

Ethanol Supply Outlook

U.S. Ethanol Supply Outlook and Issues

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 3.15 shows supply and demand for U.S. ethanol between January 2004 and May 2009. Ethanol demand set another record in May 2009 of 712 thousand barrels per day (TBD). The demand for ethanol is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal RFS2.

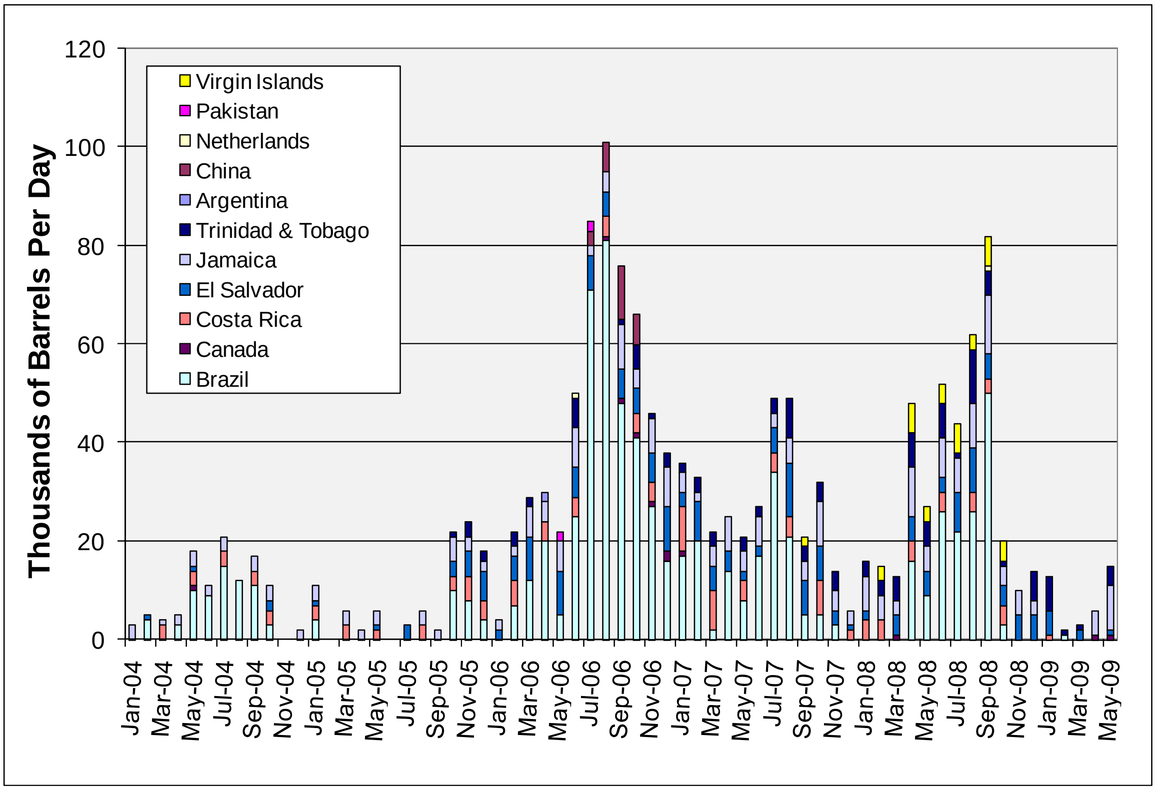
Figure 3.15: U.S. Ethanol Supply and Demand January 2004 – May 2009



Sources: Energy Information Administration (EIA) and Energy Commission analysis.

As the chart indicates, net imports of ethanol play a lesser role in the total supply picture. However, one of the key importers of ethanol over the last couple of years (Brazil) is expected to play a more pivotal role as demand for ethanol with lower carbon intensity grows in response to the California LCFS and the RFS Advanced Biofuels requirements. Figure 3.16 shows monthly U.S. net imports of ethanol between January 2004 and May 2009. Ethanol imports peaked at 100 TBD during August 2006. However, the oversupply of domestic ethanol and relatively low prices in the United States have reduced ethanol imports to modest levels during the first five months of 2009.

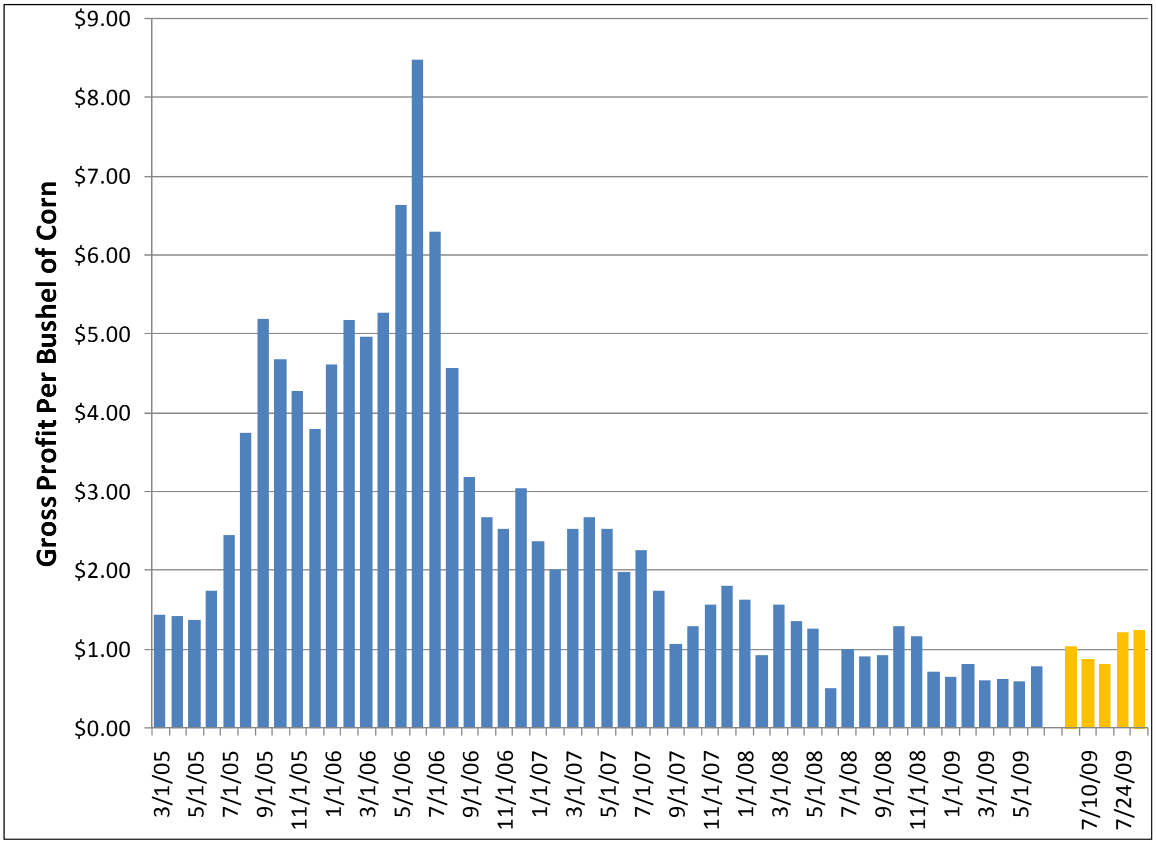
Figure 3.16: U.S. Net Ethanol Imports January 2004 – May 2009



Sources: Energy Information Administration (EIA) and Energy Commission analysis.

Several national and most California ethanol producers have recently been forced to shutter their operations due to a climate of sustained, poor production economics primarily brought about by a national oversupply of ethanol production capacity. Figure 3.17 tracks an aggregate measure of ethanol plant gross margins and shows that production economics have been significantly reduced from the highs of more than five dollars per bushel of corn processed during 2006 to less than one dollar per bushel during the early months of 2009.

Figure 3.17: U.S. Ethanol Industry Profitability March 2005 – July 2009

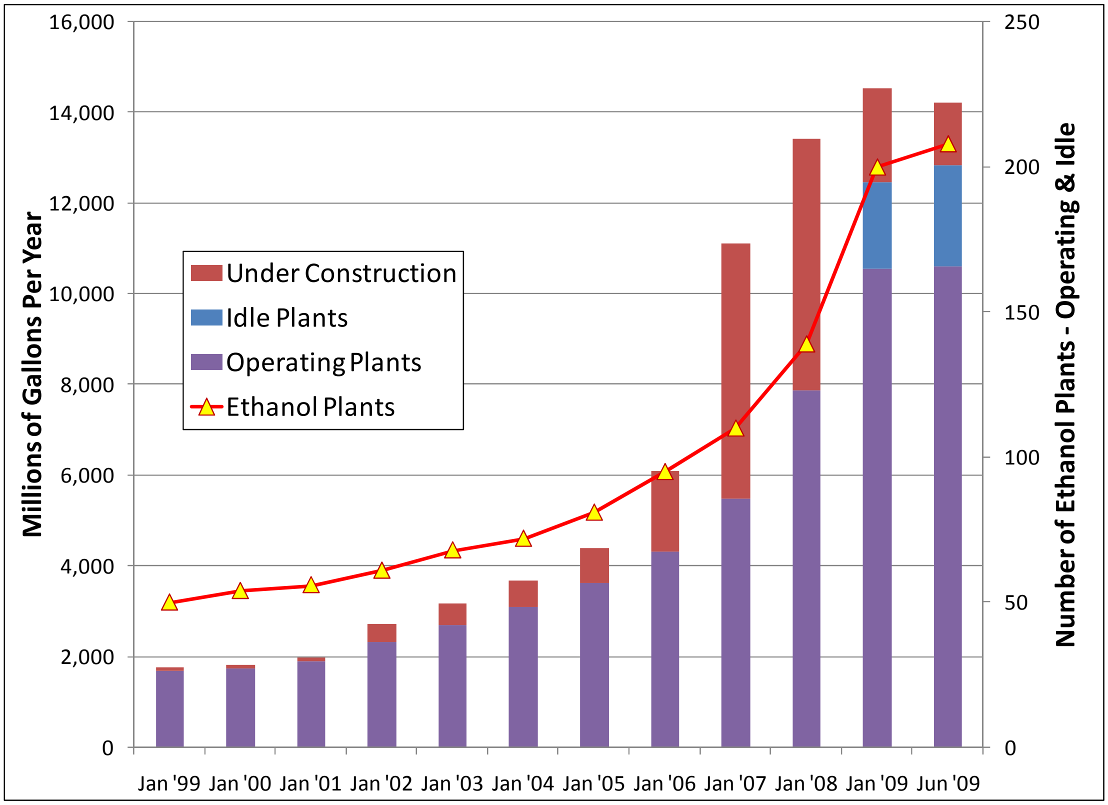


Sources: USDA - National Agricultural Statistics Service and Chicago Board of Trade (CBOT).

This development is expected to be temporary as demand for ethanol is forecast to significantly increase over the next several years as a consequence of the federal RFS regulation. In time, the oversupply of ethanol will be reduced and the profitability of the industry will likely improve. In fact, ethanol production economics show signs of improvement during July 2009, and these improved conditions may enable a number of idled facilities to resume operations. The ethanol market has experienced other periods of economic difficulties associated with changing cost structures, market price differentials between gasoline and ethanol, as well as evolving markets for various co-products.[58]

As of June 2009 there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States.[59] Figure 3.18 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 (99.3 percent of active plants, 98.3 percent of idle plants, and 92.6 percent for facilities under construction). It should also be noted that not all ethanol plants that are under construction will be completed and become operational.

Figure 3.18: U.S. Ethanol Plant Numbers and Capacities 1999-2009



Sources: Renewable Fuels Association (RFA) (January '99 – January '09) and Ethanol Producers Magazine (June '09).

Despite the recent poor economics for operating domestic ethanol plants, production capacity of conventional ethanol is expected to be adequate over the next several years as facilities resume operations and new producers come on-line after completing their construction projects. As indicated in Figure 3-18, there was 12.9 billion gallons per year of ethanol production capacity in place (either operating or idle) as of June 2009. Even if only 50 percent of the capacity under construction is completed within the next year, there will still be sufficient domestic capacity in place to meet the 2012 calendar year RFS2 obligations for corn ethanol.[60]

However, the current supply availability of certain other types of domestic ethanol is quite limited. Cellulosic ethanol production capacity is currently less than 4 million gallons per year production capacity.[61] The proposed federal RFS2 regulations require 100 million gallons of cellulosic ethanol use in 2010 and 250 million gallons in 2011. Since there is less than 5 million gallons per year of cellulosic ethanol production capacity currently under construction (as of July 2009), it is unlikely that there will be sufficient cellulosic ethanol capacity in place to meet the RFS2 obligations in 2010. In fact, the largest prospective cellulosic diesel producer identified by U.S. EPA in its proposed RFS2 regulatory package, Cello Energy, has recently been found by a federal jury in Alabama as liable for a $2.8 million breach of contract and $7.5 million in punitive damages in a court case associated with its cellulosic diesel fuel process technology claims.[62]

Therefore, U.S. EPA should delay the cellulosic obligations until commercial production capacity is actually operational. This concept would be similar to the biodiesel blending mandate in Oregon that is triggered only when a sufficient threshold of biodiesel production capacity is actually operational for a period of three months.[63] Specifically, U.S. EPA could set the national cellulosic ethanol use requirement for each January 1, based on the level of commercial-scale nameplate capacity of operating facilities in North America as of the preceding July 1.

California Ethanol Supply Outlook and Issues

Currently, five of the six California ethanol facilities are idle with a collective production capacity of nearly 240 million gallons per year. Two of the California facilities, owned by Pacific Ethanol, are in Chapter 11 bankruptcy proceedings. The remaining three idle ethanol plants are temporarily closed due to poor economic operating conditions (costs are exceeding revenue streams). Chapter 11 proceedings could result in an auction of some of California's ethanol facilities to other companies. A recent example is Sunoco's purchase of an ethanol facility in New York for $8.5 million.[64] The 100 million gallon per year capacity ethanol plant originally cost $200 million to design, permit, and construct. It is possible that another company could purchase one or more of California's ethanol plants at a large discount and/or greatly reduced debt load sufficient to enable an immediate resumption of operations and their commensurate employment gains.

Idled California facilities are expected to resume operations sometime during 2010, if not earlier. However, for this analysis, all California facilities that are currently idle are assumed to be fully operational at their rated nameplate capacity of nearly 240 million gallons per year beginning January of 2011.

Future projects to develop ethanol production that would qualify for Advanced Biofuels and Cellulosic classification continue to be permitted and discussed. However, none of these proposed projects has yet to begin construction. The potential production capacity for advanced biofuels ethanol production in California is estimated by staff at approximately 502 million gallons per year. The majority of these facilities would use sugar cane as the primary feedstock. With regard to cellulosic ethanol production projects, there are nine facilities that have been discussed with a combined capacity of 168 million gallons per year. Although these incremental volumes of planned ethanol production are significant, there remains substantial uncertainty concerning viability of these projects under the current poor ethanol economic conditions. Over the near-to mid-term period, it is likely that some of these facilities will begin construction. Since the magnitude of incremental production and timing of new facility operations is highly uncertain, staff has elected to exclude these estimated production capacity volumes from in-state ethanol availability. Over time, some portion of this planned capacity is expected to come on-line, but probably only a lesser percentage of the total within the next five years.

Brazil Ethanol Supply Outlook and Issues

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 ethanol sufficient to last until the following harvest cycle.[65] Brazilian ethanol production is also tied closely with the production of sugar from the 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 3.6 compares the ethanol industry differences in Brazil and the United States.

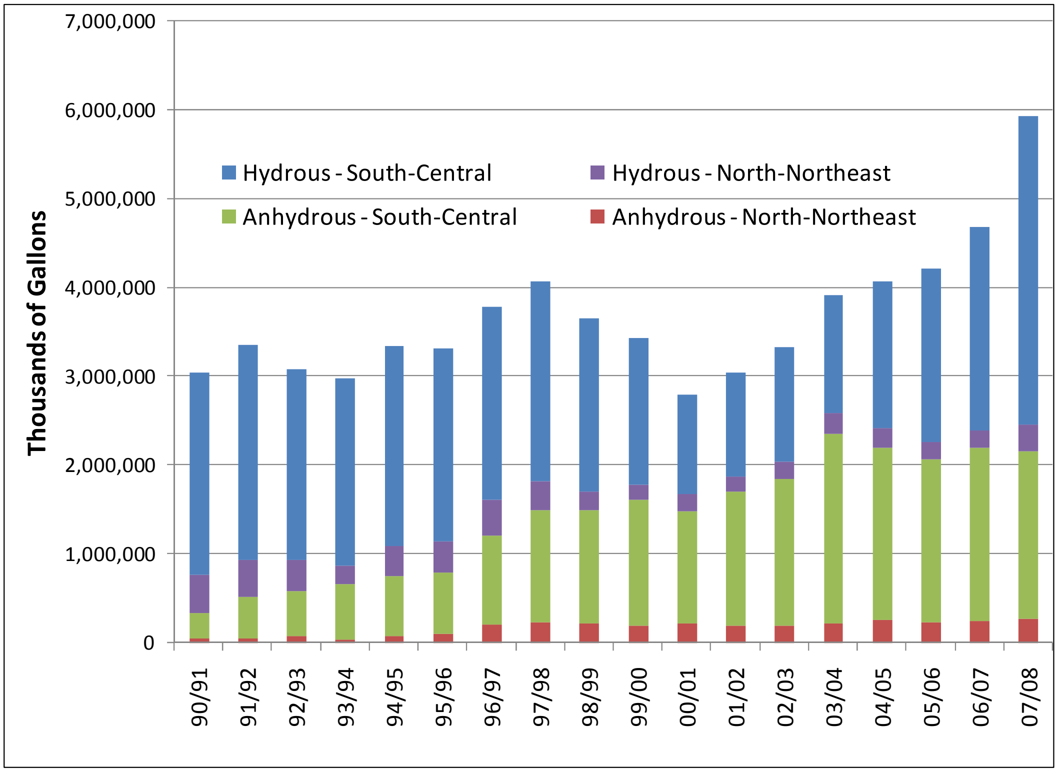
Table 3.6: Brazil and United States Ethanol Operations – 2008

2008 Comparison	Brazil	United States
Number of Ethanol Plants	96	193
Combined Number of Ethanol & Sugar Mill Facilities	229	
Total Ethanol Plants	325	193
Total Ethanol Production (Billions of Gallons)	5.9	9.2
Average Plant Production (Millions of Gallons/Year)	18.2	47.7
Ethanol Production Per Acre of Feedstock (Gallons)	678.5	432.4
Ethanol Plant Operation	Seasonal	Year-round
Long-term Feedstock Storage	No	Yes

Sources: Various and Energy Commission analysis.[66]

As is the case in the United States, Brazil ethanol production has continued to increase, setting a record output level of 5.94 billion gallons during 2008 (see Figure 3.19). Brazil produces two different types of ethanol, hydrous and anhydrous. Hydrous ethanol contains water in concentrations up to 5.6 percent by volume.[67] This type of ethanol is used in FFVs designed to operate on fuels containing between 24 and 100 percent by volume or E100 (100 percent fuel ethanol). Hydrous ethanol is also exported to other countries (especially in the Caribbean) that further process (distill) the ethanol to remove most of the water before sending to the United States, duty free under the Caribbean Basin Initiative (CBI).[68] All ethanol produced in Brazil in the initial steps of processing contains water that must be removed with an additional distillation step if the ethanol is destined for low-level gasoline blends in Brazil or final export destinations. Once the distillation 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 (up to 26 percent in Brazil and up to 10 percent by volume in the United States).[69]

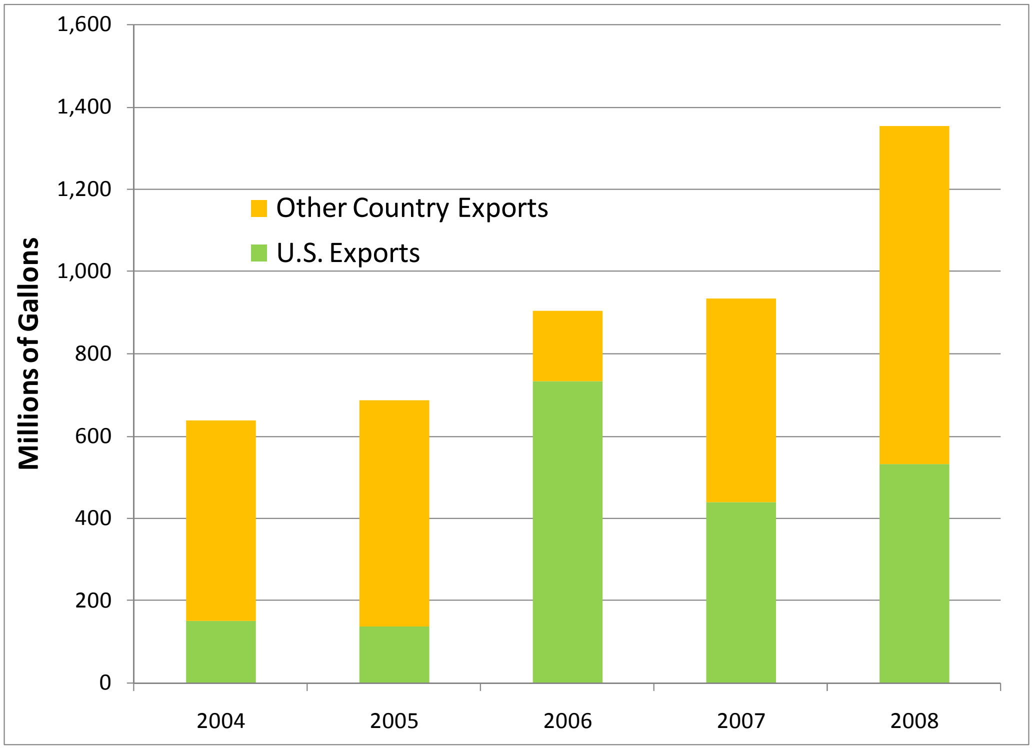
Figure 3.19: Brazil Ethanol Production 1990-2008



Sources: UNICA and Energy Commission analysis.

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. Based on the interaction of these market components there may or may not be ample excess supplies of ethanol available to export from Brazil any given year. Over the last five years (2004 through 2008), Brazil has exported between 0.60 and 1.35 billion gallons of ethanol (see Figure 3-20).

Figure 3.20: Brazil Ethanol Exports 2004-2008

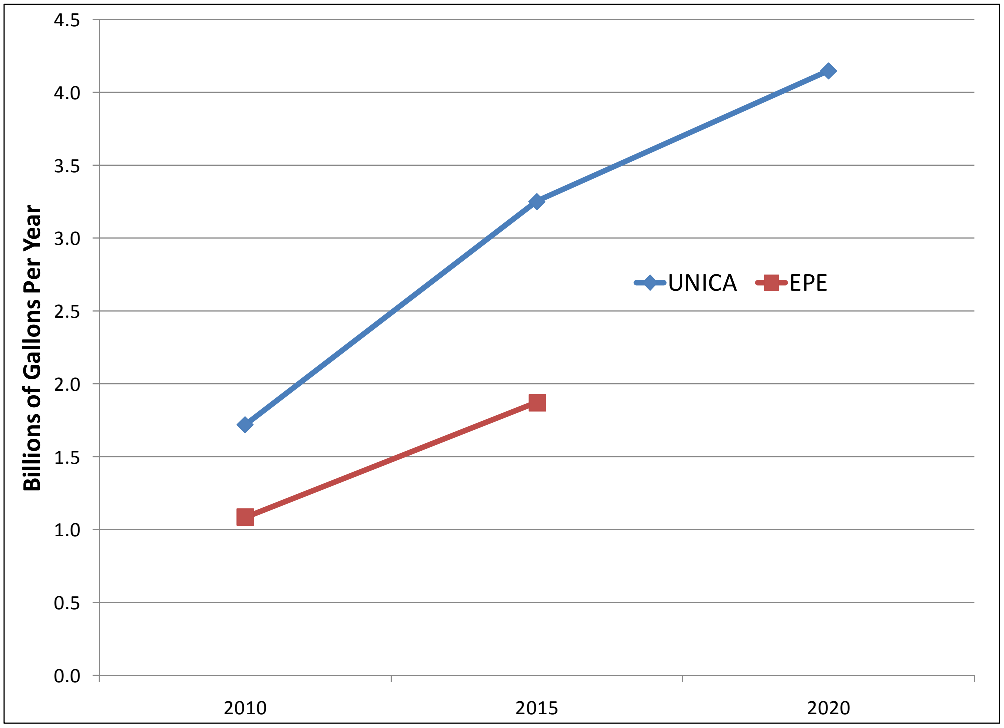


Sources: UNICA and Energy Commission analysis.

The level of Brazilian ethanol exports that arrive in the United States can vary depending on the relative price of ethanol in the U.S. market compared to the price of ethanol in other alternative destination countries. Keep in mind that Brazilian exporters of ethanol to the United States must pay two types of import duties, an ad valorem tax equivalent to 2.5 percent of the ethanol transaction price and a secondary import duty of 54 cents per gallon. Assuming ethanol is selling for $2 per gallon, the combined import duties for Brazilian ethanol would amount to 59 cents per gallon (ad valorem of 5 CPG + secondary import tariff of 54 CPG).[70] This form of protectionism increases the cost of supplying ethanol to the U.S. market and is a type of trade barrier not applied to other types of transportation fuel-related foreign imports such as crude oil, gasoline, jet and diesel fuel. Lately, a variety of stakeholders have been calling for the elimination of this ethanol import tariff, especially in light of the increased demand for Brazilian ethanol that is likely to materialize as a consequence of the federal RFS Advanced Biofuels requirement and California's LCFS for gasoline carbon intensity. Modeling work assessing the potential impact of removing the 2.5 percent ad valorem and the secondary import tariff suggest that the price of ethanol in the United States could be reduced from 2.5 to 14 percent, a potential benefit to consumers.[71]

The amount of excess ethanol that may be available to import from Brazil over the next several years is forecast to grow to between 1.9 billion and 3.2 billion gallons by 2015.[72] Figure 3.21 illustrates estimates from UNICA and Empresa de Pesquisa Energética or Energy Planning Agency of the Ministry of Mines and Energy of Brazil (EPE).

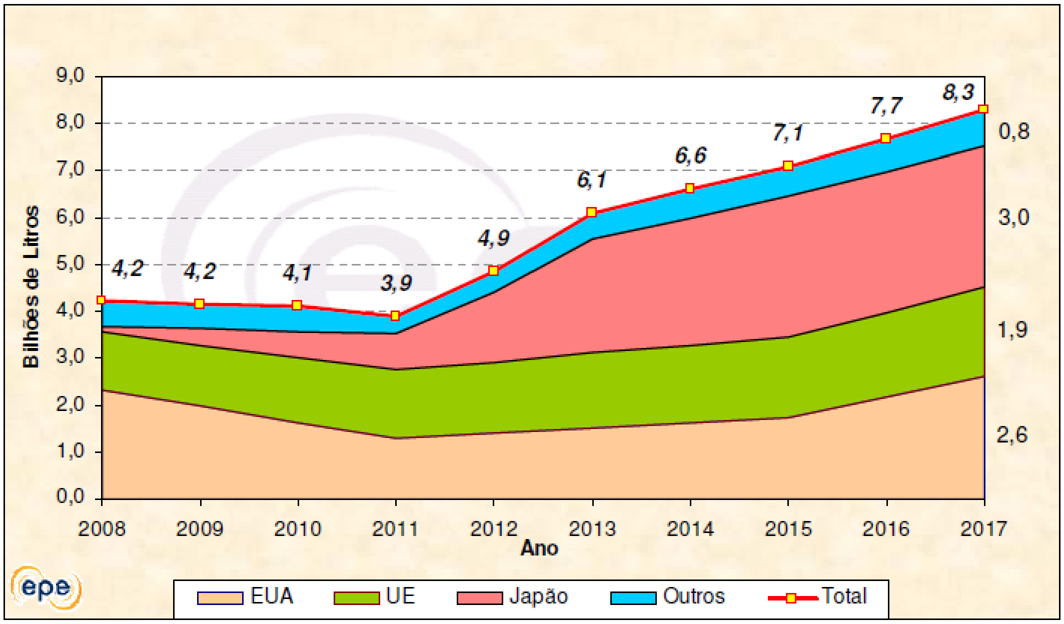
Figure 3.21: Brazil Ethanol Export Forecast



Sources: UNICA and EPE.

EPE's forecast of Brazil ethanol exports is more conservative than the Brazilian sugarcane industry association's outlook, especially when you consider that the EPE export estimate for 2010 is less than the 2008 total of 1.4 billion gallons. Although these forecast ethanol export volumes are sizable and could be used to achieve compliance with the Other Advanced Biofuels portion of the RFS2 requirements, keep in mind that Brazil has a certain volume of export obligations to locations other than the United States. One example is Japan, which is why EPE's forecast has a greater quantity of ethanol destined for that country (see Figure 3.22 for the graph used in its report that contains the relative ethanol export quantities by destination country).[73] The units of the chart are billions of liters, while "EUA" is the designation for the United States, "UE" for the European Union, and "Japão" for Japan.

Figure 3.22: EPE Forecast of Brazil Ethanol Exports by Destination

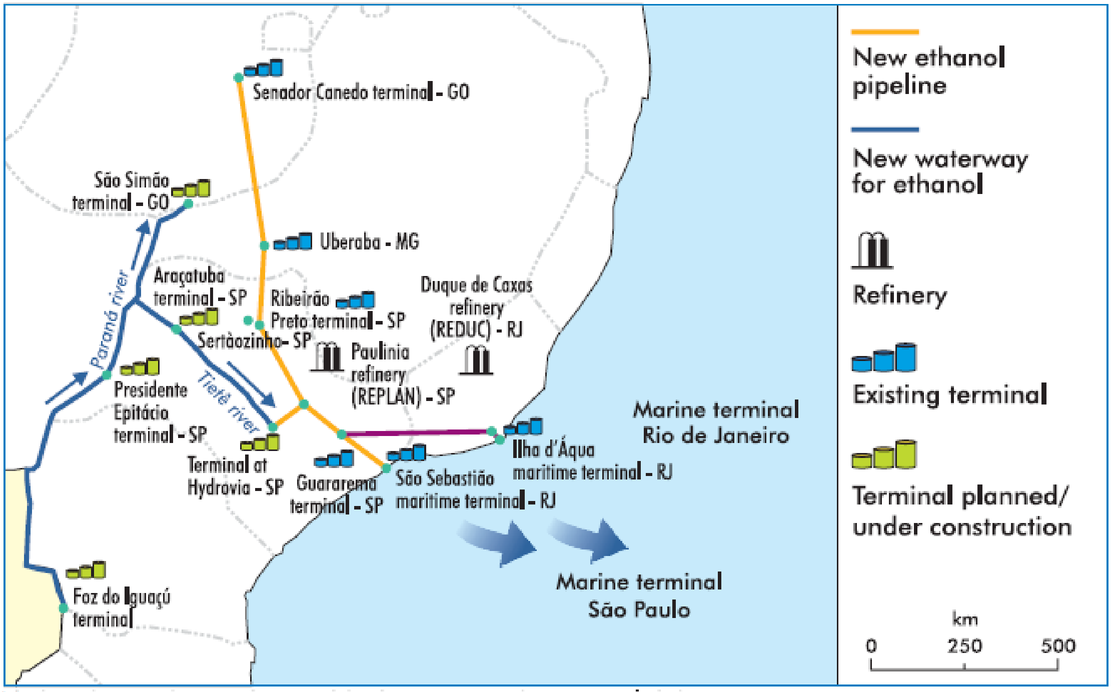


Source: *Perspectivas Para O Etanol No Brasil*, Empresa de Pesquisa Energética (EPE), page 33.

Other marketers throughout the United States will also be competing for Brazil ethanol as they attempt to comply with the Advanced Biofuels requirements of the RFS2 through acquisition and blending of this type of ethanol, rather than through the purchase of RIN credits from other marketers or RIN aggregators. Therefore, the market price for Brazil ethanol is expected to command a premium to California-sourced ethanol, which should be more valuable than conventional corn-based ethanol produced outside the state. The anticipated higher, yet unknown, prices are assumed to be passed along to consumers.

Brazil continues to develop an infrastructure that is designed to increase the quantity of ethanol that can be exported to destinations such as the United States. In fact, Brazil is the only country that transports ethanol over significant distances via pipelines that are also used to ship petroleum products. Figure 3.23 shows the existing and expanded infrastructure associated with an expansion of ethanol exports.

Figure 3.23: Expansion of Brazil Ethanol Export Infrastructure



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: State abbreviations are: GO – Goais; SP – São Paulo; MG – Minas Gerais; RJ – Rio de Janeiro.

Sources: Petrobras and World Energy Outlook 2006, page 478.

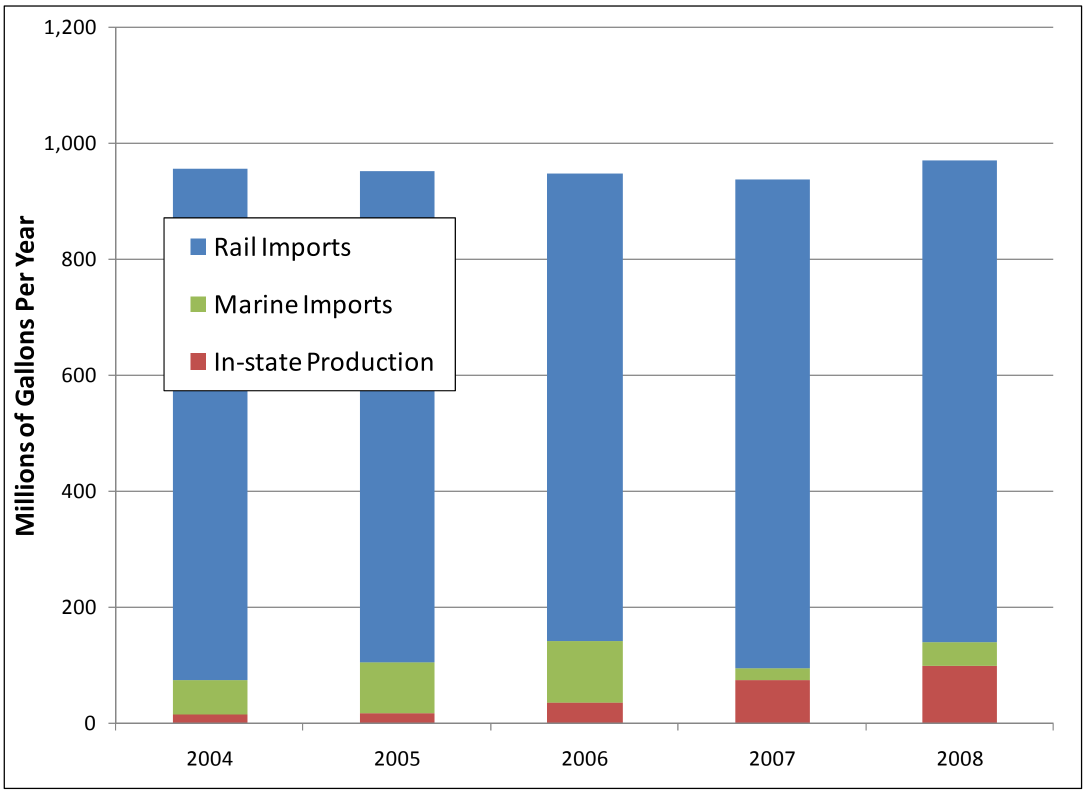
California Ethanol Logistics Outlook and Issues

It is clear that the quantity of ethanol used in California transportation fuels will increase over the next couple of years as refiners and other marketers react to higher levels for ethanol that will be mandated by the RFS2 requirements. In addition, the California LCFS is expected to further complicate matters by 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 redistribution of ethanol will need to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months.

Ethanol Rail Logistic

Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest. The majority of these imports are via unit trains that consist of between 90 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. The unit train receiving facility in Carson, California, supplies most of the ethanol to meet the needs of Southern California.[74] Northern California does not have a comparable type of rail receipt facility, at this time, and receives imports of ethanol via a combination of manifest rail cars and ocean-going marine vessels. Historically, the balance of ethanol supplies is obtained from California ethanol facilities. However, as discussed earlier, the majority of California's ethanol plants are temporarily shuttered due to poor economics. Figure 3.24 breaks down the sources of ethanol for California over the last five years. During this period, rail imports have accounted for an average of 88.4 percent of California ethanol supply, followed by marine imports (6.6 percent) and in-state production (5.0 percent). During 2008, rail imports represented 85.7 percent, followed by higher in-state production (10.1 percent) and marine imports (4.2 percent).

Figure 3.24: California Ethanol Supply Sources 2004-2008



Sources: Energy Information Administration (EIA), California state Board of Equalization (BOE) and Energy Commission analysis.

Ethanol Distribution Terminal Logistics

California's ethanol import and redistribution infrastructure will need to change rather quickly to accommodate the anticipated transition to 10 percent (E10) blending beginning January 1, 2010. Commencing on that date, Kinder Morgan will accept only base gasoline that will be used to blend E10 at all of their California distribution terminals. Since the majority of the 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), it is expected that most if not all of California's gasoline market will switch to E10 during the first part of 2010. Based on the results of a confidential survey conducted by the Energy Commission, it is likely that an adequate infrastructure will be in place to increase ethanol blending by more than 50 percent (compared to 2009 levels). Types of modifications that are already underway or complete include the construction of new ethanol storage tanks and increased capacity to receive tanker trucks of ethanol. There still remains a possibility that all of the necessary modifications will not be completed as scheduled. If so, temporary logistical difficulties could arise during the initial months of the transition to E10. Even so, the industry is expected to adjust rather quickly and efficiently to correct any shortcomings within a relatively short period.

Kinder Morgan also continues to make progress on its project to enable the receipt of ethanol unit trains into the Richmond area.[75] Unlike the unit train facility in Southern California, this facility is designed to transfer the ethanol directly from the rail cars to the tanker trucks via a process called transloading.[76] Kinder Morgan has experience in this type of ethanol rail receipt and transfer operation as it transloaded 15,000 rail cars of ethanol in 26 markets throughout the United States in 2007.[77] The completion and operation of this project should help ensure that Northern California will have sufficient capacity to receive ethanol via rail cars to accommodate the increase to E10 blending during 2010. However, as discussed earlier, the LCFS is expected to drive refiners and other obligated parties to seek out types of ethanol with lower carbon intensities, such as ethanol from Brazil. This anticipated import requirement could be necessary as early as the beginning of 2011.

Ethanol Marine Logistics

Marine imports of ethanol to California have been limited over the last several years due primarily to an abundance of ethanol production capacity in the United States and the import tariff for most sources of foreign ethanol. Consequently, the capacity to receive significant quantities of ethanol via marine vessel has not been needed. However, that situation could be altered due to the changing mix of ethanol sources and the potential impact on marine import infrastructure requirements. At this time, it is uncertain how much incremental ethanol could be imported into California via marine vessel. Over the short-term, operators of marine import facilities could commit additional storage tanks for receiving ethanol imports. The conversion of storage tanks from one type of service (gasoline, diesel, or jet fuel) to ethanol service does not pose a technical difficulty. These types of decisions would reduce the ability of individual marine facility operators to import other petroleum products, unless overall import capacity was to increase.

If California were to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside of California. Along these lines, Primafuel has received permits to construct a new marine terminal in Sacramento that is designed to import up to 400 million gallons of ethanol per year.[78] At this time, construction has not been initiated. If the facility were to be operational by January 2011, construction would need to begin before the end of 2009. Reticence on the part of potential customers appears to be the primary hurdle at this time. The proposed Sacramento renewable fuels hub terminal would greatly increase the marine ethanol import capability of Northern California such that there should be sufficient capacity to receive Brazilian ethanol over the near to mid-term period.

Additional imports of Brazilian ethanol into California could also be accomplished via unit trains originating in another port city outside California. For example, ethanol from Brazil could be imported through the Houston ship channel and transferred to rail cars before delivery to California. Although no specific project has been publicly announced to date, development of this type of capability would increase the likelihood that sufficient capacity could be in place to import significant quantities of Brazilian ethanol.

Ethanol Trucking Logistics

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 rail receipt hub terminals. As California moves to higher concentrations of ethanol in gasoline (E10) and an anticipated increase in E85 sales, a greater number of truck trips will be required to supply sufficient quantities of ethanol to all of these distribution terminals. An anticipated increase of more than 50 percent for the number of truck trips could place a temporary burden on trucking resources (both the number of qualified drivers and the number of tanker trucks rated to haul ethanol); any logistical difficulties that may manifest themselves should be corrected within a couple of months as the industry quickly adapts to higher ethanol blending rates in California.

Ethanol Pipeline Logistics

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.[79] However, this practice is unlikely to be extended to California over the near to mid-term due to the increased age and complexity of the existing California pipeline system, as well as a higher probability of water in the pipeline system due to changes in the pipeline elevation (hydraulic profile).[80] 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, it should be noted that 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.

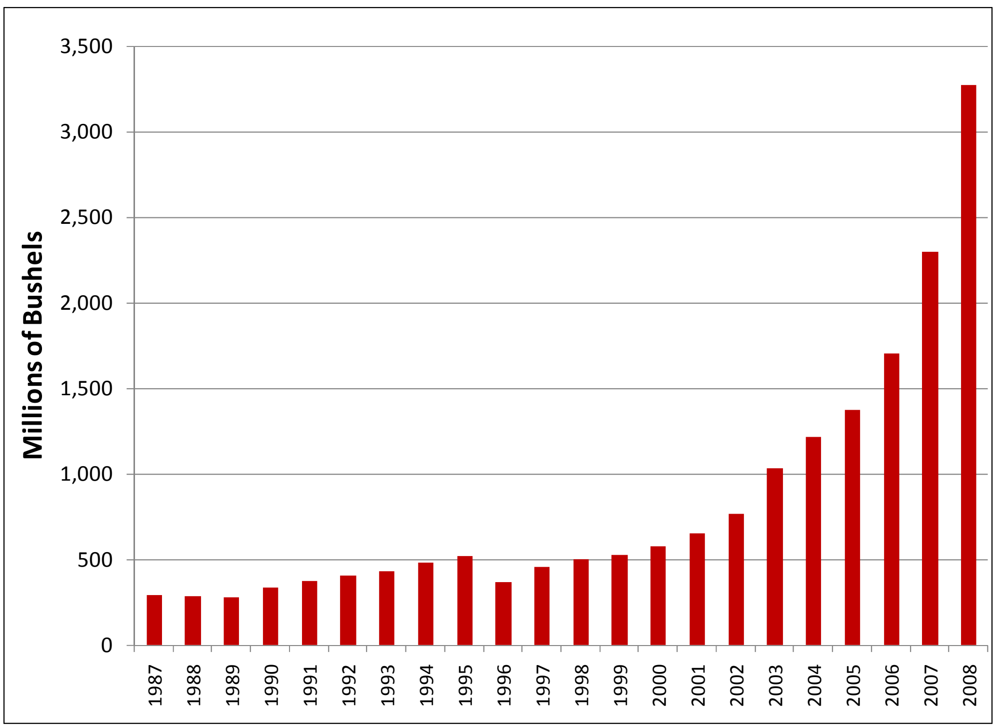
This discussion would not be complete without mentioning a recent proposal to construct a pipeline dedicated solely to ethanol shipments. A pipeline company (Magellan Midstream

Partners, LLP) and an ethanol company (POET) have signed a joint development agreement to "continue assessing the feasibility of constructing a dedicated ethanol pipeline." The project is designed to gather ethanol from ethanol facilities located in the Midwest and transport to renewable fuel as far as 1,700 miles to the Northeast United States.[81] The ultimate cost of this undertaking could be $3.5 billion and requires some level of federal loan guarantees. A similar concept for a dedicated pipeline in California would likely be economically unattractive since California does not have a large concentration of ethanol plants that normally sell their ethanol to markets that are over 1,000 miles distant.

Renewable Fuels and Agriculture

The majority of fuel ethanol in the United States is produced in facilities that use corn as the primary feedstock. As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. Figure 3.25 illustrates the quantity of corn that was used annually to produce ethanol since 1987.

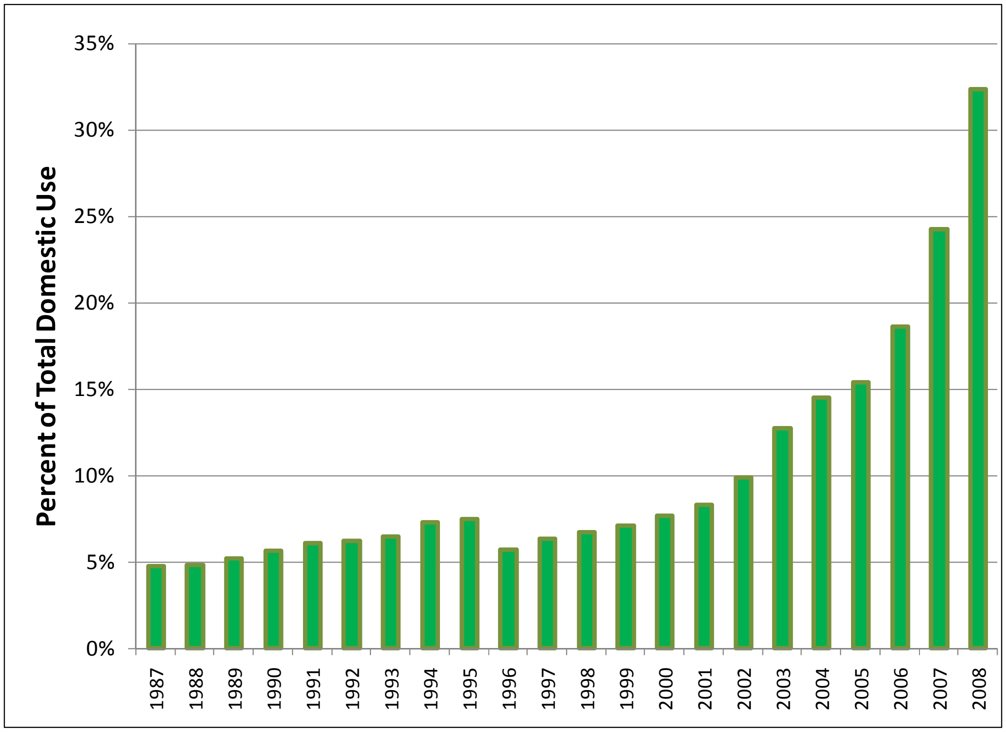
Figure 3.25: U.S. Corn Demand for Ethanol Production 1987-2008



Source: USDA - National Agricultural Statistics Service.

During the earlier years of ethanol use, corn demand for producing ethanol was a small percentage of total domestic use. However, the portion of corn required to produce ethanol has been increasing at an accelerated pace and accounted for approximately 32.3 percent of domestic corn use in 2008. Figure 3.26 shows the increasing use over the last 22 years.

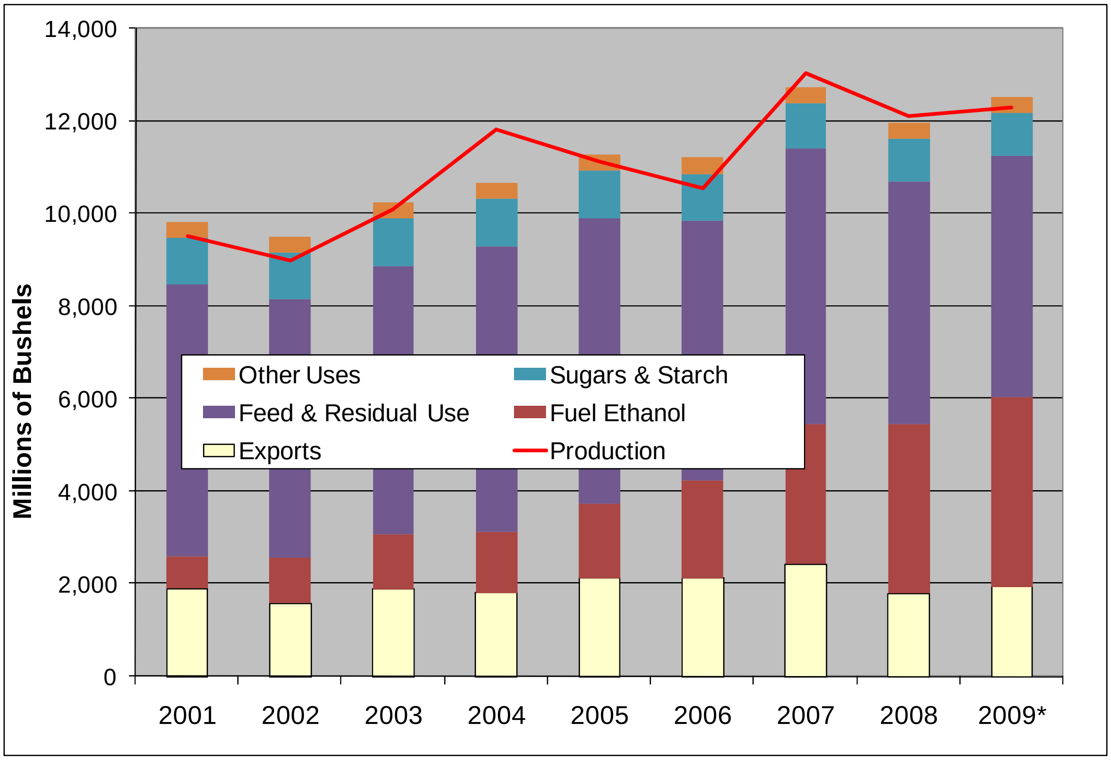
Figure 3.26: U.S. Percent of Corn Demand for Ethanol Production 1987-2008



Sources: USDA - National Agricultural Statistics Service and the Energy Information Administration (EIA).

Other uses of corn (including a feedstock for ethanol production) are shown in Figure 3.27 between 2001 and 2009. It should be noted that the 2009 values are USDA forecasts.

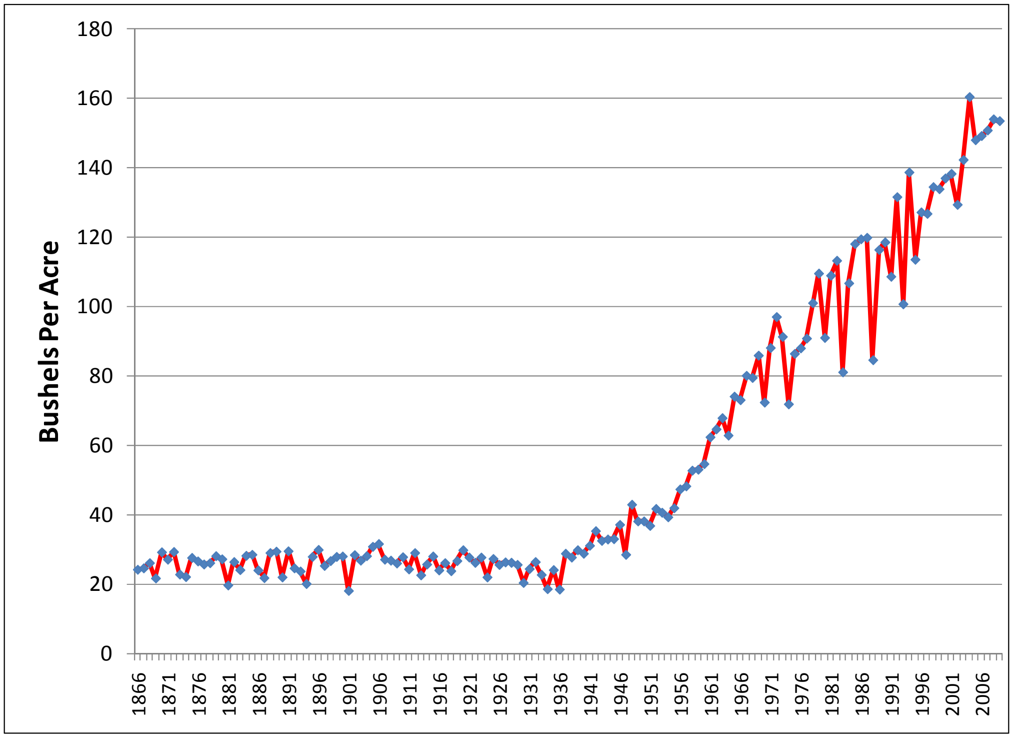
Figure 3.27: U.S. Corn Production and End Use 2001-2009



Sources: USDA - National Agricultural Statistics Service and Energy Commission analysis.

The ability of the agricultural markets to keep pace with the rapid demand to produce ethanol from corn has largely been accomplished via a continual improvement in the average yield of corn per acre (see Figure 3.28).

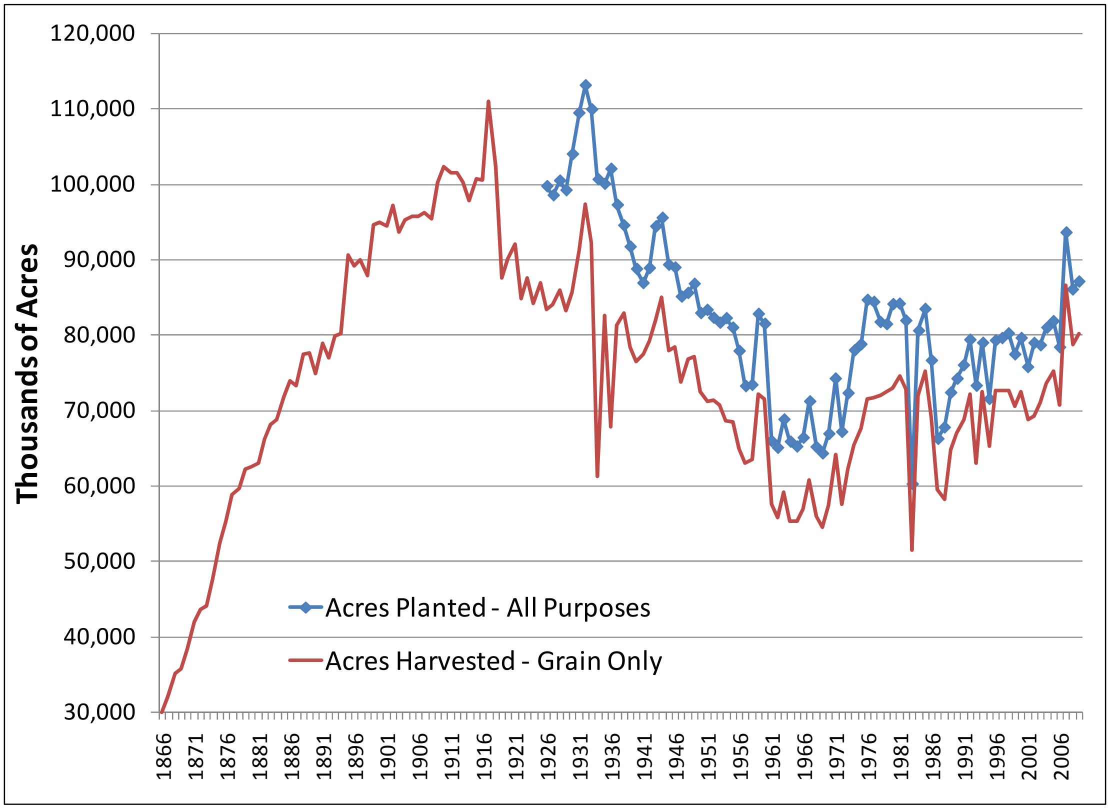
Figure 3.28: U.S. Annual Corn Yield 1866-2009



Source: USDA - National Agricultural Statistics Service.

The near-continuous yield improvement (as measured in bushels harvested per acre) has been accomplished through increased application of fertilizer up through the early 1980s, followed by improved strains of crops and use of geographic information systems (GIS) to allow for the more precise application of fertilizer and plowing techniques. All of these advances and improved practices have enabled greater production of corn without any significant expansion of the number of acres planted. In fact, the 78.6 million acres of corn harvested in 2008 is 32.3 million acres less than the record 110.9 million acres in 1917. Despite the lower total, 2008 corn production of 12.1 billion bushels was more than four times the 1917 production of 2.9 billion bushels. Figure 3.29 shows the progression of corn plantings between 1866 and 2009.

Figure 3.29: Acres of Corn Planted and Harvested 1866-2009

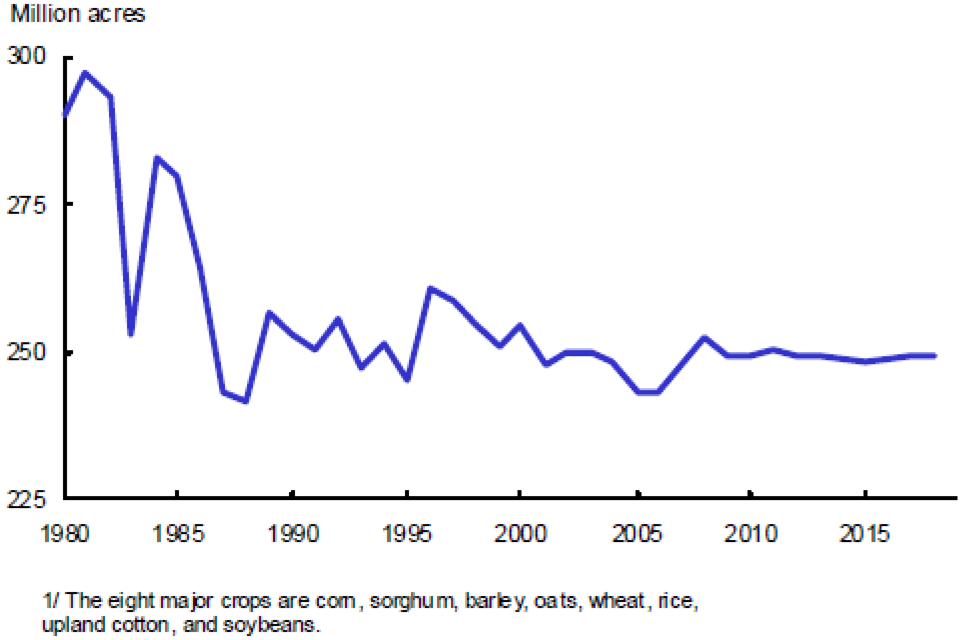


Source: USDA - National Agricultural Statistics Service.

The increased demand for corn to produce even greater quantities of ethanol is a near-certainty since the RFS-mandated ethanol levels allow for up to 15 billion gallons of ethanol per year to originate from facilities that use corn as a feedstock. One consequence of this growing demand for corn-based ethanol is that the quantity of corn required to produce up to 15 billion gallons per year of ethanol will be higher than the 3.27 billion bushels estimated to produce the 9.24 billion gallons of ethanol in 2008. Assuming the amount of corn required to produce one gallon of ethanol remains the same (approximately 2.8 gallons of ethanol per bushel of corn processed), the minimum corn demand to produce up to 15 billion gallons of ethanol could top 5.3 billion bushels by 2015. According to the USDA, the quantity of corn for production of fuel ethanol is forecast at 4.825 billion bushels for market year 2015/16.[82]

Potential deleterious impacts on other crops could occur if increased demand for corn for ethanol production were accomplished by expanding corn acreage by replacing other field crops, such as wheat and soybeans. Agricultural land in the United States is considered to be a somewhat finite resource. However, Congress does have the ability to adjust the maximum number of acres that are permitted to be included in the Conservation Reserve Program (CRP) through the passage of a revised Farm Bill.[83] Figure 3.30 highlights the point that the USDA forecast is assuming flat projections for the total acres planted for the eight major crops over the forecast period.

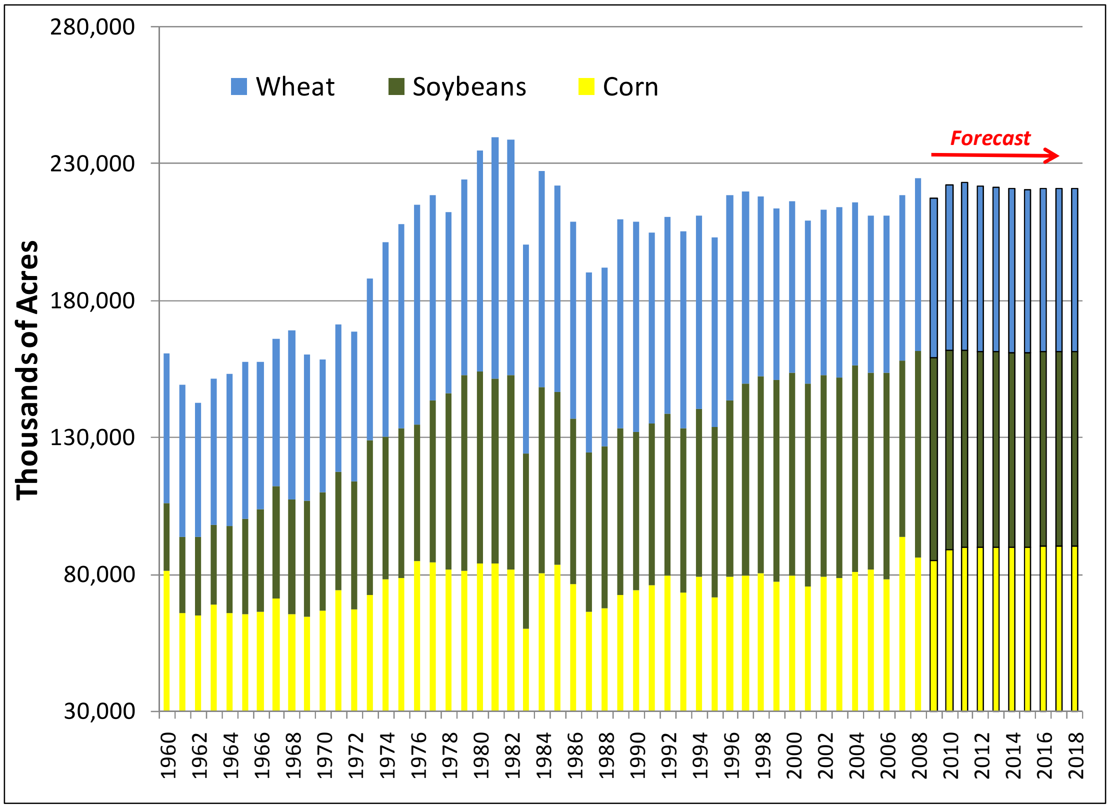
Figure 3.30: U.S. Major Crop Plantings 1980-2018



Source: USDA Agricultural Projections to 2018, February 2009, page 18.

Since the acres of farmland dedicated to major crops are expected to remain relatively status quo over the next nine years, what does this trend portend for corn, soybeans, and wheat plantings that have been routinely characterized as interchangeable? Figure 3.31 shows the historical plantings for these three crops, along with the USDA forecast. As the chart illustrates, total acres for all three actually *decrease* by 1.7 percent compared to 2008, while corn acres planted are forecast to be 5.3 percent greater compared to 2008.

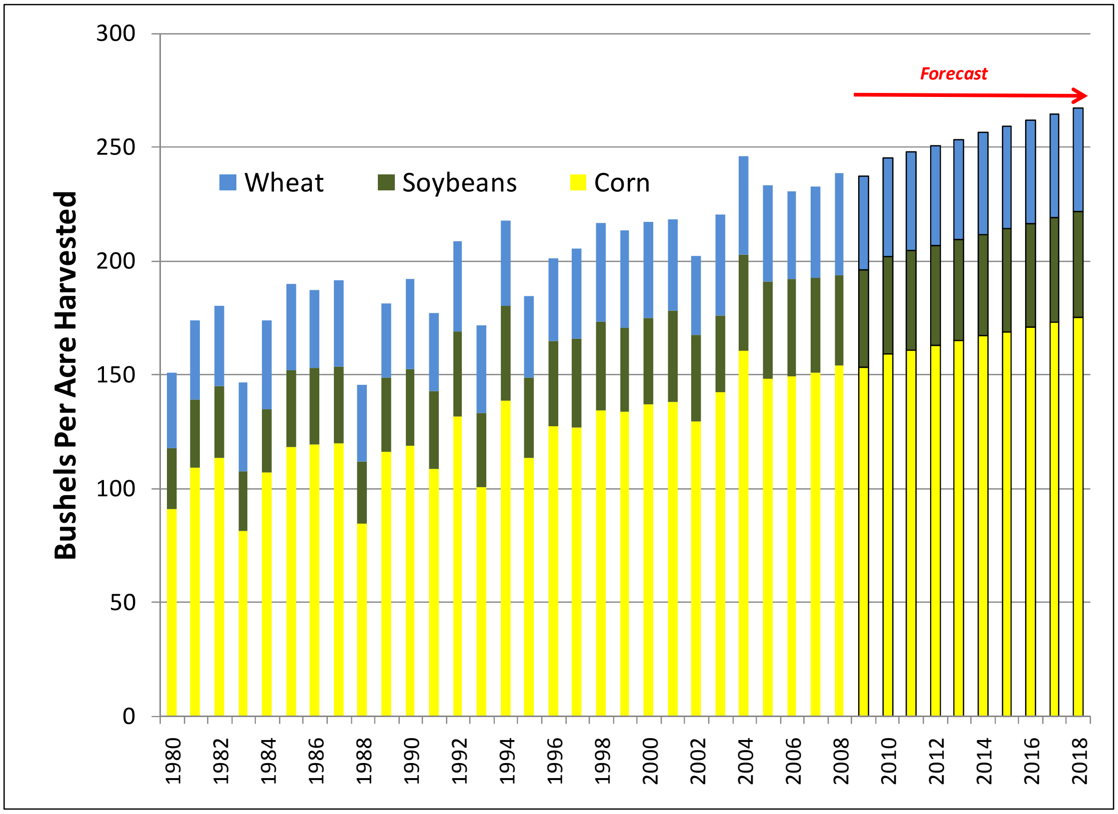
Figure 3.31: U.S. Corn, Soybean, and Wheat Plantings 1980-2018



Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009.

This USDA outlook means that the combined acres planted for wheat and soybeans will decrease by 6 percent by 2018 when compared to 2008. Therefore, it seems as though the expansion of corn planting will come at the expense of reduced wheat and soybean plantings. Although the planted acres are expected to decline over the forecast period, total production actually rises by 11.6 percent for soybeans but declines 7.6 percent for wheat between 2008 and 2018. This feat is accomplished through a continued improvement in the average production yield per acre over the forecast period. Figure 3.32 shows the respective annual yields for corn, soybeans, and wheat for both the historical and forecast period.

Figure 3.32: U.S. Corn, Soybean, and Wheat Yields 1980-2018

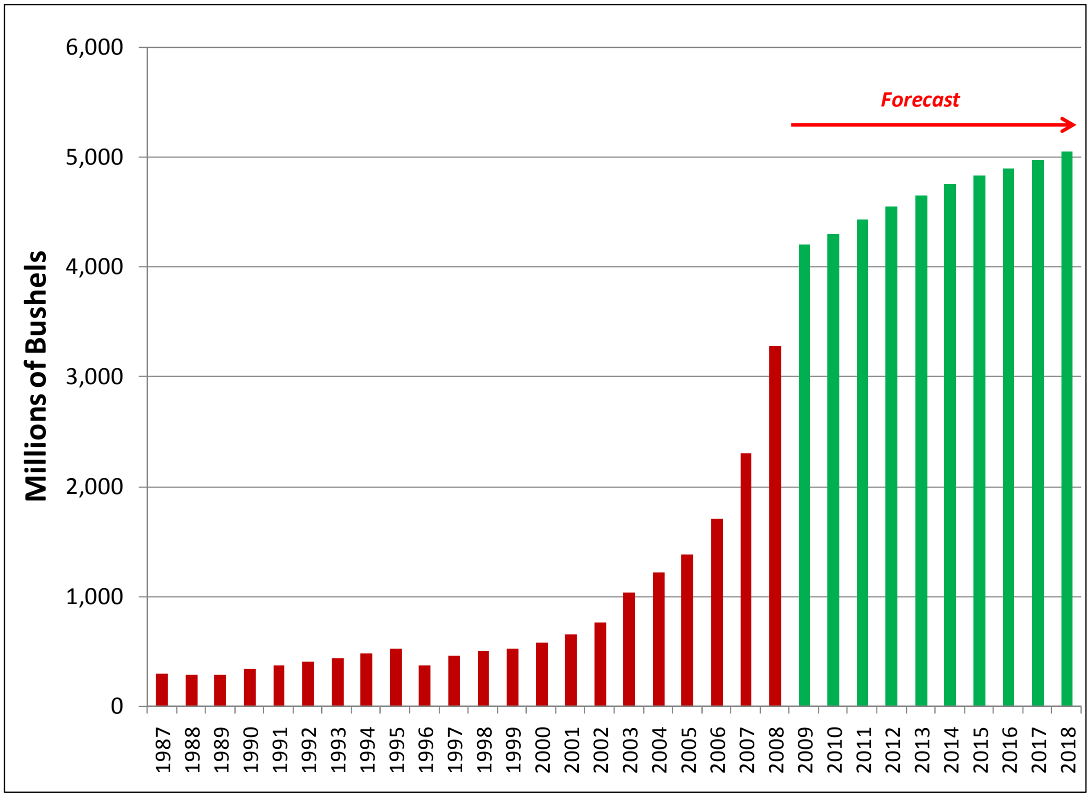


Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009.

Production yields as measured in number of bushels per acre harvested have been continually increasing for several decades due to improvements in agricultural practices and genetics. USDA assumes in its forecast that this trend of increasing yields will continue between 2008 and 2018. Corn yields are forecast to rise from 153.8 bushels per acre harvested in 2008 to 175.0 bushels per acre by 2018, an increase of 13.8 percent. Soybean yields are forecast to grow by 18.3 percent (39.3 to 46.5 bushels per acre), while wheat yields are forecast to rise by only 1.8 percent (44.9 to 45.7 bushels per acre) over the forecast period.[84]

Although continuous yield increases in the forecast seem justified by the historical growth rates, it should be noted that actual yields for any particular crop during a growing season can be negatively affected by poor weather conditions (insufficient rains for dry-cropping or flood damage from severe storms) and increased levels of destruction from disease or pests. Therefore, any decrease in either yields or the number of acres planted over the forecast period could result in less production (in terms of bushels) for corn, soybeans, and other major crops as portrayed in the USDA projections. Lower-than-expected production of corn could raise market prices and negatively impact the profitability of ethanol plant operators. Figure 3.33 overlays the USDA corn demand forecast for ethanol production with the historical demand since 1987.

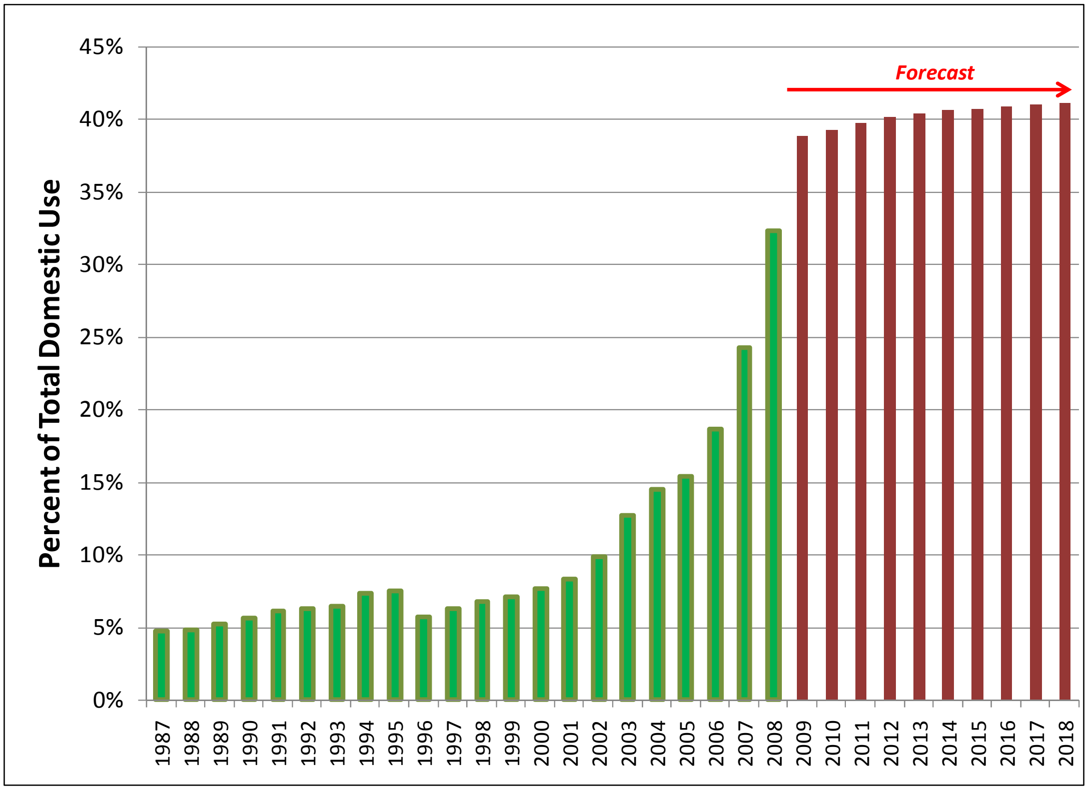
Figure 3.33: U.S. Corn Demand for Ethanol Production 1987-2018



Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009, page 33.

The rather dramatic increase in corn demand for producing ethanol does not appear as drastic when viewed as a percentage of total domestic use, as shown in Figure 3-34. As this chart indicates, the percentage nearly levels out at 41 percent since other use of corn are also increasing over the forecast period, just not as quickly.

Figure 3.34: U.S. Percentage of Corn Demand for Ethanol Production 1987-2018



Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009, page 18.

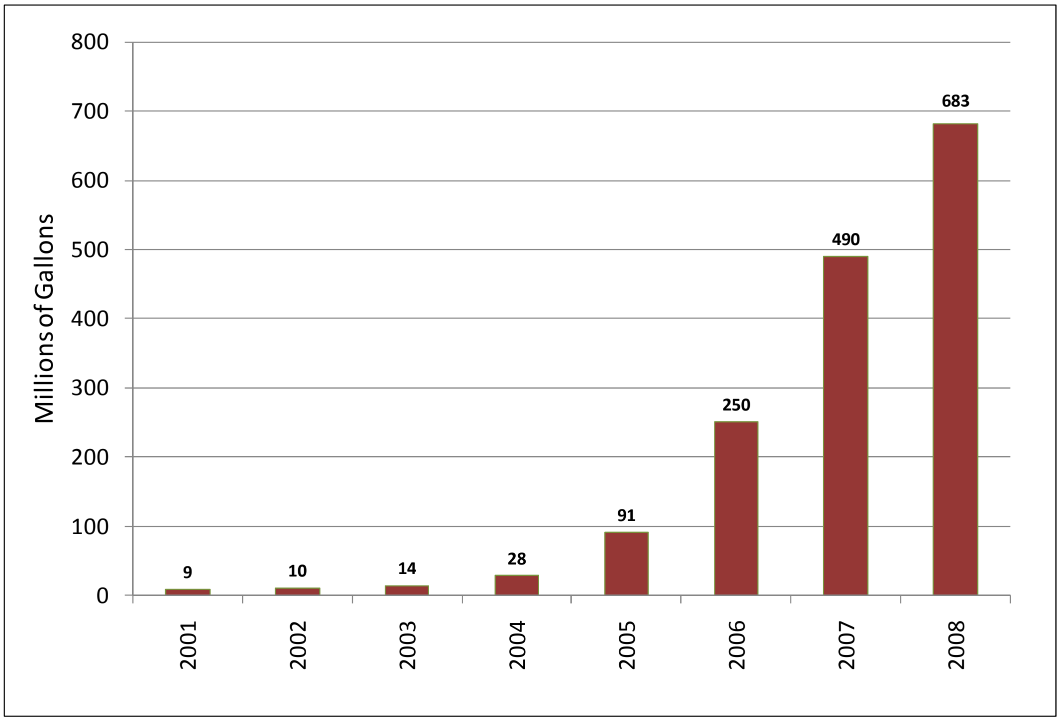
Biodiesel Overview

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.[85] 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.[86] 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.[87] Currently, retail sales of biodiesel in California are quite modest but will likely increase for the same reason as ethanol (the state LCFS and the federal RFS2).

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 to 5 percent of B100 mixed with the conventional diesel fuel to meet American Society for Testing and Materials (ASTM) specification D975. Higher blends of B100 between the range of 6 and 20 percent by volume must meet ASTM specification D7467.[88] A survey of biodiesel producers in the United States was conducted in 2004 to identify the properties of both B100 and B20.[89]

Production of biodiesel in the United States has dramatically increased over the last couple of years (see Figure 3.35) in response to federal legislation that included $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel that went into effect in 2005.[90] Output is expected to continue growing as refiners and other obligated parties strive to meet mandatory biodiesel blending requirements mandated by RFS2 (see RFS biodiesel discussion later in chapter).

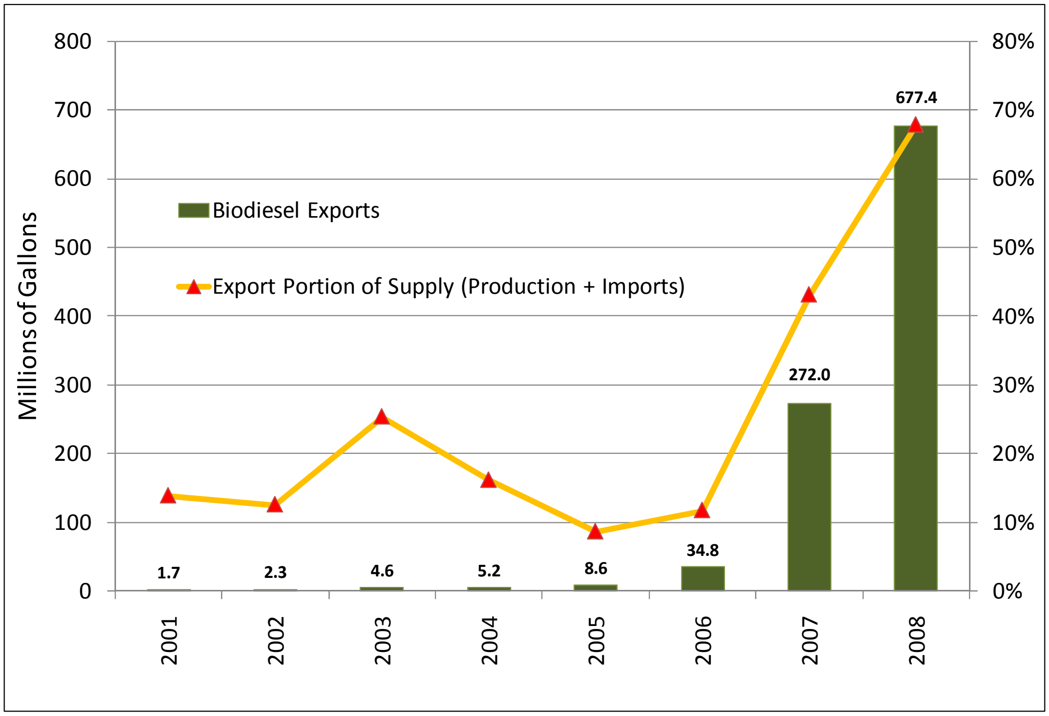
Figure 3.35: U.S. Biodiesel Production 2001-2008



Source: Energy Information Administration (EIA).

Significant quantities of biodiesel have been exported over the last couple of years due to more attractive wholesale prices and U.S. exporters' use of the dollar-per-gallon biodiesel blenders' credit (see Figure 3.36). Biodiesel exports have grown from nearly 9 million gallons in 2004 to more than 677 million gallons in 2008. As the chart also indicates, a growing percentage of total U.S. biodiesel supply has been exported, rather than used in domestic transportation fuels. In 2008 alone, export volumes represented 68 percent of total U.S. biodiesel supplies (production combined with imports).

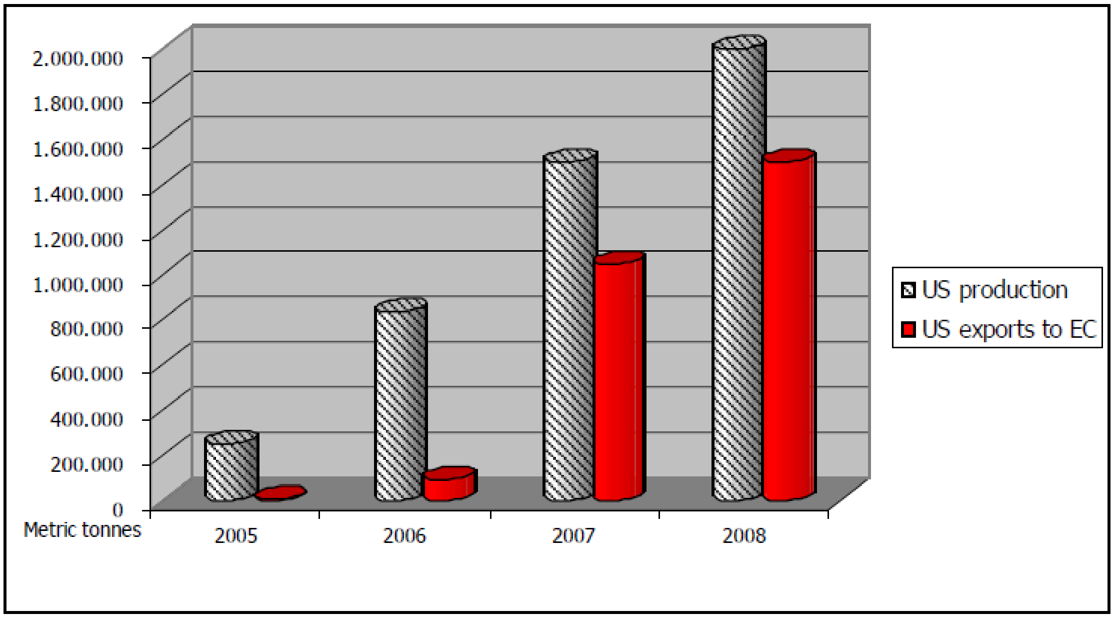
Figure 3.36: U.S. Biodiesel Exports and Percentage of Total Supply 2001-2008



Source: Energy Information Administration (EIA).

According to the European Biodiesel Board, a significant quantity of the U.S. biodiesel production was exported to European Union countries, especially over the last couple of years (see Figure 3.37).[91] However, the continuous flow of biodiesel exports to Europe from the United States is not expected to be maintained since the European Union has recently taken action to apply a combination of import duties (both countervailing and anti-dumping) that were approved in July 2009 for a period of five years.[92] These new tariffs are designed to compensate for the economic advantage gained by United States biodiesel exporters from the dollar-per-gallon blenders' credit.[93] As a consequence of thee actions, United States exports of biodiesel have declined back to 16 percent of supply based on the most recent information available from April 2009.

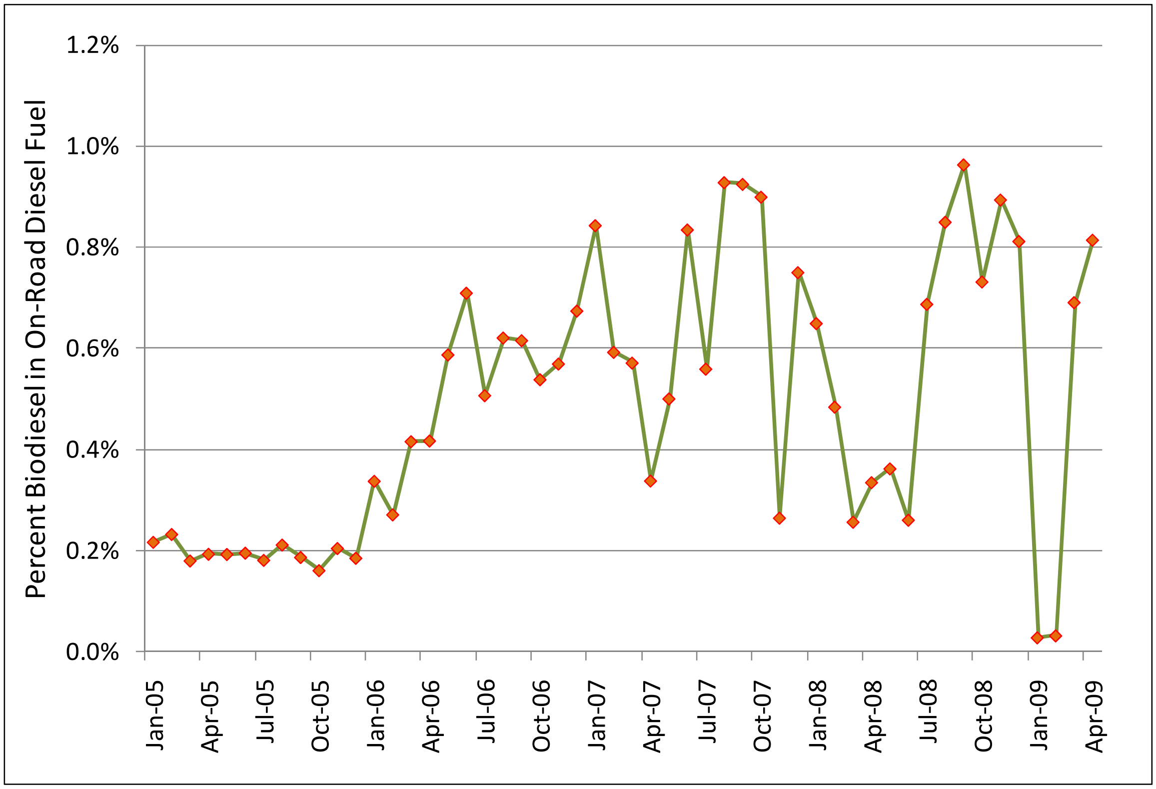
Figure 3.37: U.S. Biodiesel Production and Europe Exports 2005-2008



Source: European Biodiesel Board (EBB) – approximately 300 gallons of biodiesel per metric tonne.

The large exodus of domestic biodiesel production from the United States to Europe has resulted in biodiesel blending levels that have fluctuated between 0.2 and 1.0 percent as illustrated by Figure 3.38. Absent the large increase of biodiesel exports, blending levels in the United States could have increased to an average of 1.29 percent during 2008, rather than the actual 2008 average of 0.61 percent. It is expected that the application of the EU tariffs will result in a decrease of biodiesel exports and an increase of the average biodiesel concentration in the United States. Over the next couple of years, production and use of biodiesel is expected to grow due to higher levels mandated by the RFS2 regulations.

Figure 3.38: U.S. Biodiesel Blending Levels 2005-2009

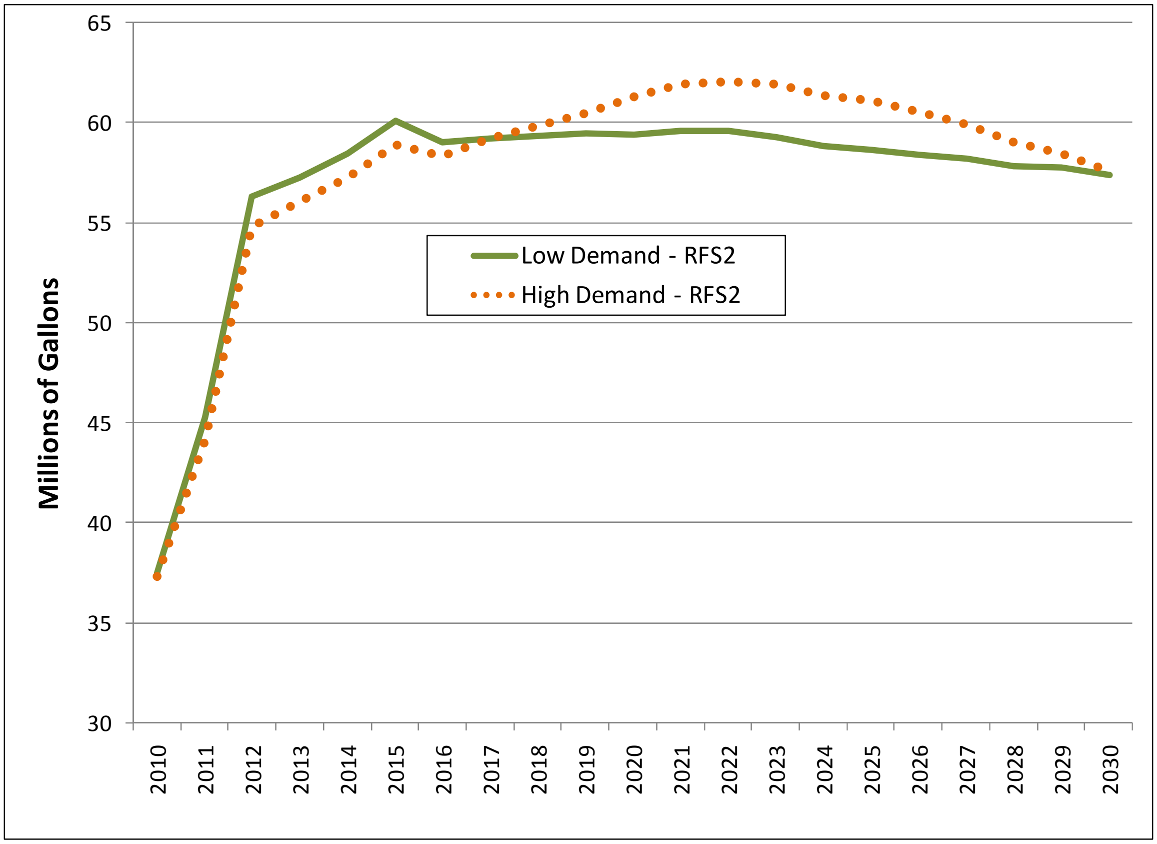


Sources: Energy Information Administration (EIA) and Energy Commission analysis.

Renewable Fuels Standard – Increased Demand for Biodiesel

Earlier in this chapter the RFS2 "fair share" obligations for California were presented for both ethanol and biomass-based diesel fuel. Under the Low Diesel Demand Case, biodiesel "fair share" ranges from 38 million gallons in 2010 to 57 million gallons by 2030. Under the High Diesel Demand Case, biodiesel "fair share" ranges from 37 million gallons in 2010 to 58 million gallons by 2030 (see Figure 3.39). Based on these projected volumes, California's average biodiesel blending concentration is not expected to be higher than 1.8 percent. However, California's LCFS requirements are anticipated to increase the level of biodiesel use to significantly higher levels that have yet to be fully quantified (see LCFS discussion below).

Figure 3.39: California Biodiesel Demand Forecast 2010-2030



Source: Energy Commission analysis.

Increased Biodiesel Use in Retail Diesel Fuel – B5 to B20

Retail diesel fuel dispensers and USTs are certified to handle diesel fuel that contains biodiesel at concentrations of up to 20 percent by volume. However, these same USTs have not received independent testing organization approvals for biodiesel blends greater than 5 percent (B5) and up to 20 percent (B20). To provide additional time for these approvals to be developed, the California State Water Resources Control Board (SWRCB) issued emergency regulations that took effect on June 1, 2009, that allowed for a 36-month variance from this UST requirement.[94] This action has removed a potential barrier to expanded use of biodiesel in California. Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations. However, for those retail locations that want to dispense B99 or B100, storage of biodiesel at these concentrations in an underground storage tank may not be permissible at this time per the California State Water Resources Control Board (SWRCB). Therefore, retailers still have the option to store B99 or B100 in an aboveground storage tank (AGT). Installation of a new AGT would be significantly more expensive than using an existing UST that is currently used to store and dispense diesel fuel.

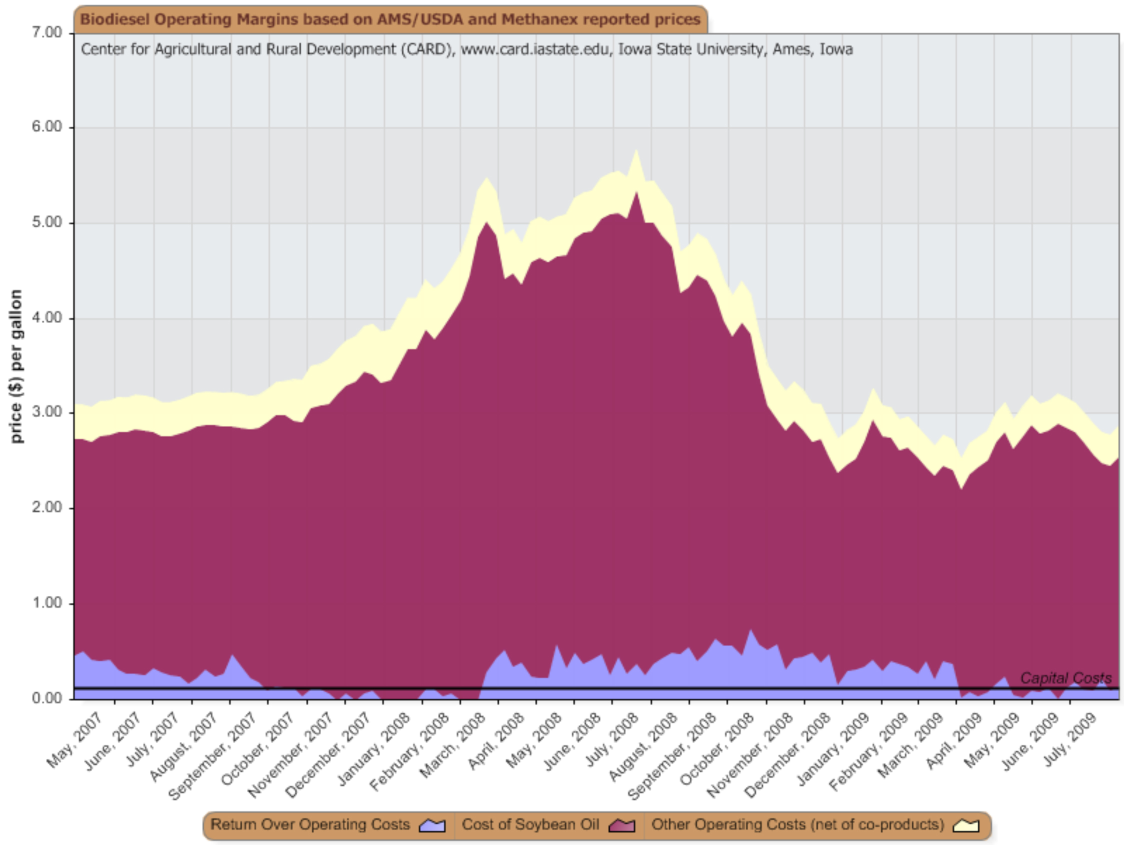
LCFS and Biodiesel

As explained earlier in this chapter, there has been no quantitative analysis performed to determine how the volumes and types of biodiesel used in California could change as a consequence of the LCFS. When additional carbon intensity pathways for various types of biodiesel are published, the Energy Commission will conduct analysis to identify any potential supply or infrastructure issues that could result over the near to mid-term period. Currently, only two types of biodiesel (and renewable diesel) have direct and indirect carbon pathways published by ARB, waste oil and tallow. Based on the carbon intensities of these fuels, refiners and other obligated parties could fully comply with the per-gallon diesel LCFS requirements in B20 blends of diesel fuel (20 percent biodiesel and 80 percent conventional diesel fuel).[95] However, it should be noted that both of these alternative diesel types are quite limited from a supply perspective. Therefore, sole dependence on these alternative diesel fuels for LCFS compliance is extremely unlikely.

U.S. Biodiesel Supply Outlook and Issues

The RFS2 regulations call for a minimum use of one billion gallons per year of biomass-based diesel fuel by 2012. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating U.S. facilities, along with another 595 million gallons per year of idle production capacity, and another 289 million gallons per year capacity under construction.[96] It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the RFS2 requirements for several years. The large number of idle ethanol facilities is not surprising as the economics for biodiesel producers have deteriorated through most of 2009 as evidenced by the recent trends illustrated in Figure 3.40. As is the case with ethanol, it is anticipated that these poor biodiesel production economics are temporary and will continue to improve as demand for biodiesel grows through the RFS2 mandates and the LCFS necessity to reduce the per-gallon carbon intensity of diesel fuel in California.

Figure 3.40: U.S. Biodiesel Operating Margins May 2007 – July 2009



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

Biodiesel Supply Outlook

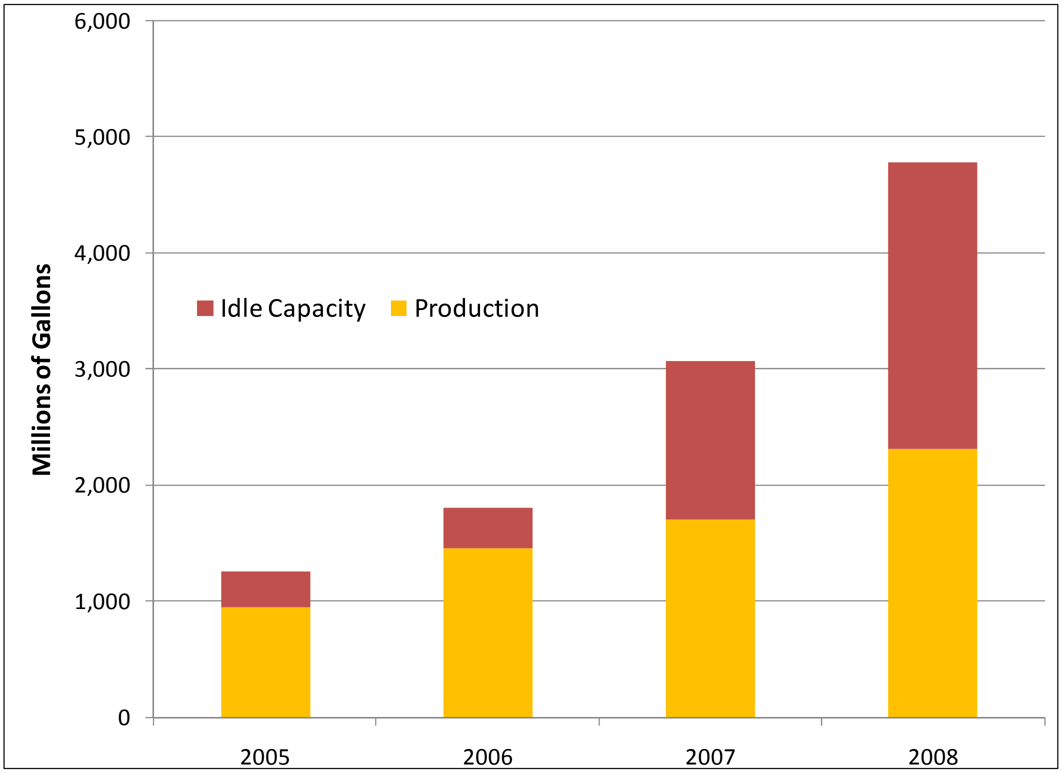
California Biodiesel Supply Outlook and Issues

According to *Biodiesel Magazine*, there are 10 biodiesel production facilities operating in California with an annual production capacity of 63 million gallons, along with 3 idle plants with a combined production capacity of 8 million gallons.[97] Although these production volumes are insufficient to supply all of California's "fair share" of biodiesel, there should be ample biodiesel production capacity outside the state to provide the necessary balance to meet the High Demand Case for biodiesel use of 61 million gallons by 2020.

Europe Biodiesel Supply Outlook and Issues

Europe continues to be the dominant producer of biodiesel in the world, estimated to possess approximately 68 percent of the global production capacity.[98] Over the last couple of years, production capacity has increased from 1.26 billion gallons per year in 2005 to 4.79 billion gallons per year in 2008 (see Figure 3.41). However, a growing percentage of these biodiesel facilities have been idled by poor economics and less expensive imports from the United States. Despite these poor operating conditions, Europe biodiesel production capacity is estimated to reach 6.25 billion gallons during 2009.[99]

Figure 3.41: Europe Biodiesel Production and Idle Capacity 2005-2008



Source: European Biodiesel Board (EBB).

California Biodiesel Logistics Outlook and Issues

Infrastructure requirements for biodiesel are similar to that 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 would then need to be hauled to distribution terminals that dispense diesel fuel destined for truck stops and other retail locations. Although similar in need, the biodiesel infrastructure has not been developed to the same extent as that of ethanol primarily because there has not been any meaningful increase in the use of biodiesel to date. It is likely that changing circumstances could require a sizable increase in the use of biodiesel and a commensurate development of the associated distribution infrastructure to ensure adequacy of diesel fuel supplies for California. Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use.

Biodiesel Distribution Terminal Logistics

Biodiesel is blended with diesel fuel as the tanker truck is loaded before delivery to the retail station. As such, the biodiesel (B100) must be stored in segregated tanks. Unlike ethanol, only a few distribution terminals have biodiesel storage capabilities due to significantly lower demand levels when compared to ethanol. At this time, biodiesel use is discretionary and at very low concentrations (on average). That situation is expected to change as refiners and other marketers in California move to comply with both the RFS2-mandated biodiesel blending requirements and the additional volumes that will surely be necessary to reduce the per-gallon carbon intensity of diesel fuel per the LCFS.

Distribution terminal modifications will need to be made over the near to mid-term to help ensure sufficient volumes of biodiesel will be available 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 already being continuously used. 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 Rail Logistics

The majority of biodiesel use in California is believed to originate from production facilities located within the state. Approximately 50 million gallons of biodiesel was used as transportation fuel during 2008, slightly less than the operating biodiesel production capacity more than 60 million gallons per year. Over the next several years, biodiesel volumes are expected to increase. It is possible that biodiesel demand levels could exceed 10 or even 20 percent of total diesel fuel used in the transportation sector. If so, demand volumes could easily surpass 400 to 800 million gallons per year by 2022.[100] Assuming sufficient spare production capacity throughout the United States to meet this potential increase in California biodiesel demand, it is likely that most of the incremental biodiesel will originate from facilities located outside the state. This means that imports of biodiesel may be necessary via rail and/or marine vessel. Currently, there are no biodiesel rail facilities designed to handle unit trains. Ultimately, biodiesel unit train receipt capability may not be necessary due to demand levels that may be too low to justify the expense. It is more probable that rail receipts of biodiesel will be transferred to tanker trucks via transloading, as is the case with the Kinder Morgan ethanol transloading project in Northern California. In fact, staff believes that there is already a modest amount of biodiesel transloading occurring in California, a practice that is expected to grow over the next several years.

Biodiesel Marine Logistics

Periodically, biodiesel has been imported into California by marine vessels. Due to cargo sizes that are smaller than ethanol, the storage tank requirements to unload the biodiesel are more modest. Optimal storage tank sizes are less than 10 thousand to 50 thousand 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. In fact, a marine terminal in Southern California that was recently closed had been used periodically for importation of biodiesel. Availability of marine facilities is limited and would need to be made available if meaningful volumes of biodiesel were to be imported via marine vessel. However, as was previously discussed, there is sufficient domestic biodiesel production capacity to supply California's anticipated needs over the near to mid-term that could reasonably be delivered in rail cars, rather than marine vessels.

Biodiesel Truck Logistics

As is the case 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. Since the volume and associated trucking requirements are less than that of ethanol, incremental trucking requirements should not be as pressing. For example, assuming an incremental 300 million gallons per year of biodiesel was being transported to California distribution terminals, approximately 50 additional tanker trucks may be necessary (assuming two trips per truck per day). Although the additional trucking requirements may be modest, most distribution terminals would need to be modified so that the biodiesel could be received and transferred to segregated storage tanks at the terminals (a capability that all of the terminals have for ethanol today). This ultimate capability will require both time and an unquantified capital expense to complete.

Biodiesel Pipeline Logistics

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 (1/10) of the cost compared to tanker truck delivery.[101] Pipeline distribution companies have recently initiated shipments of biodiesel blends in portions of certain pipeline networks. One such example is the recent distribution of diesel fuel containing up to 5 percent by volume biodiesel (B5) in portions of Kinder Morgan's Plantation Pipeline located in the Southeastern United States.[102] It should be noted that there are operational restrictions that limit this practice. The primary concern of transporting biodiesel blends in mixed petroleum product pipeline systems is the potential contamination with jet fuel. At present, Kinder Morgan is restricting biodiesel blend shipments to portions of their pipeline system that do not handle any jet fuel. 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 needs for delivery of biodiesel to distribution terminals via tanker trucks.

Transportation Natural Gas

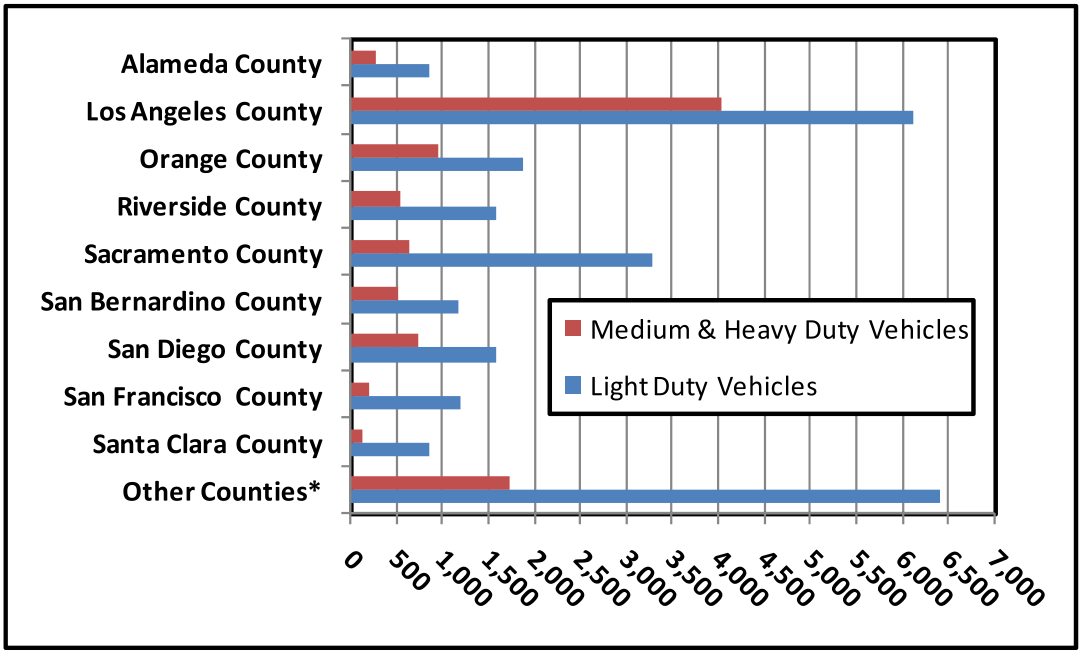
Natural gas has been an established vehicle fuel in California for more than 20 years. This fuel accounts for approximately 25 percent of the total energy used for all purposes in the United States and 87 percent of the natural gas used is domestically produced in the United States.[103] Traditionally, natural gas is less expensive than gasoline and diesel on an energy basis and is provided as a transportation fuel in one of two forms: CNG or LNG. CNG is simply natural gas compressed to pressures above 3,100 pounds per square inch. LNG is liquefied by cooling the natural gas to temperatures below -260°F at normal pressure.

Natural gas vehicles have many environmentally friendly attributes including: emitting 60 to 90 percent less smog producing pollutants and 30 to 40 percent less GHG emissions[104] than gasoline and diesel-powered engines for light duty vehicles. Currently, ARB is placing a proposed 75.2 to 75.6 carbon intensity value (gCO_2e/MJ)[105] on CNG delivered via a pipeline. The environmental profile of natural gas can be further improved through advancements in biomethane or biogas, which are renewable sources for the production of natural gas. This production method of creating natural gas and converting it to CNG has been estimated to have a 12.5 carbon intensity value (gCO_2e/MJ) by ARB, which is less than 1/6th of the current value for conventional fossil fuel natural gas sourced from North America and 87 percent less than gasoline GHG emissions.

Natural Gas Vehicles

In 2008, there were 24,810 light-duty CNG vehicles[106] registered and operating in California with less than half of these vehicles (10,747) as being registered to individual owners (see Figure 3.42). This represents a significant increase over 2000 totals of 3,082; however, the light-duty natural gas vehicle population has been relatively flat since 2001. State and local governments accounted for 31 percent of the ownership of light-duty CNG vehicles with 78 percent of those vehicles existing in government vehicle fleets of 1,000 vehicles or more. In addition to light-duty vehicles, there were an additional 9,674 medium-and heavy-duty natural gas vehicles registered in California in 2008, with 7,144 of those vehicles being buses, most of them CNG-powered. The remaining medium- and heavy duty vehicle population is spread across various vehicle types with the greatest number of them being garbage trucks (1,003). These counts represent significant increases in natural gas vehicles over the total of 3,640 for all natural gas-powered vehicles registered in 2000.

Figure 3.42: Natural Gas Vehicle Counts by Specific Counties, October 2008



Source: Energy Commission analysis of DMV Vehicle Registration Database

*The Other Counties category is composed of counties with less than 500 light duty natural gas vehicles

Several different vehicle manufacturers have produced light-duty CNG vehicles, but currently only the Honda GX CNG is offered for sale in the United States[107]. The lack of vehicle offerings was identified as one of the primary hurdles to natural gas becoming a major publicly used transportation fuel in California[108]. Another barrier is that light-duty CNG vehicles often require more frequent refueling due to having approximately 25 percent less range than gasoline or diesel vehicles per one tank of fuel. And like electric vehicles, natural gas vehicles are so unfamiliar to the majority of consumers that they are unable to generate favorable impressions among many potential car buyers.

Natural Gas Refueling

Southern California Gas Company lists 90 publicly accessible natural gas refueling stations[109] in Southern California, as well as around 200 private stations. An additional eight stations are identified by Clean Energy in the Northern/Central California region. Refueling options could be further increased through the use of a Home Refueling Appliance (HRA)[110], which could be used to refuel a CNG vehicle tank at an owner's home. This refueling process takes on average anywhere between 5 to 8 hours to fill 50 miles worth of natural gas and requires the owner to have access to a natural gas line. Installation of these devices is reported to be easy but they do require professional installation[111]. This could represent a significant advantage for natural gas vehicles in commuter settings since the owner of such a unit could eliminate refueling at public stations from normal weekly activities.

Strategies for Increased Adoption

Several factors were identified at an Energy Commission workshop that would potentially promote the use of natural gas as a transportation fuel[112]. Foremost is to increase light-duty OEM natural gas vehicle offerings. A successful strategy for siting of refueling facilities has been to target high-volume customers such as taxi fleets and heavy trucks. But replicating this success in the general public requires simultaneously developing refueling infrastructure that is targeted to emerging geographic clusters of vehicle purchasers. The new infrastructure needs to find investment money and policy incentives that encourage that investment, although several companies are executing business models that are expanding the infrastructure. The price of fuel can be very attractive to high-volume purchasers, but vehicle cost can be a barrier to more light-, medium-, and heavy-duty vehicle purchases unless alleviated by declining production costs, driven by on-board fuel storage needs or consumer incentives. The *State Alternative Fuels Plan - AB 1007 Report* also identified several actions that would encourage the development of the industry: develop new utility rate structures for HRAs; stimulate the development of biomethane/biogas for use in natural gas vehicles and as a feedstock for hydrogen; improve on-board storage technology to improve the range and costs of natural gas vehicles; develop natural gas hybrid electric technology; and use the GHG emission benefit credits in investment and business operation plans.

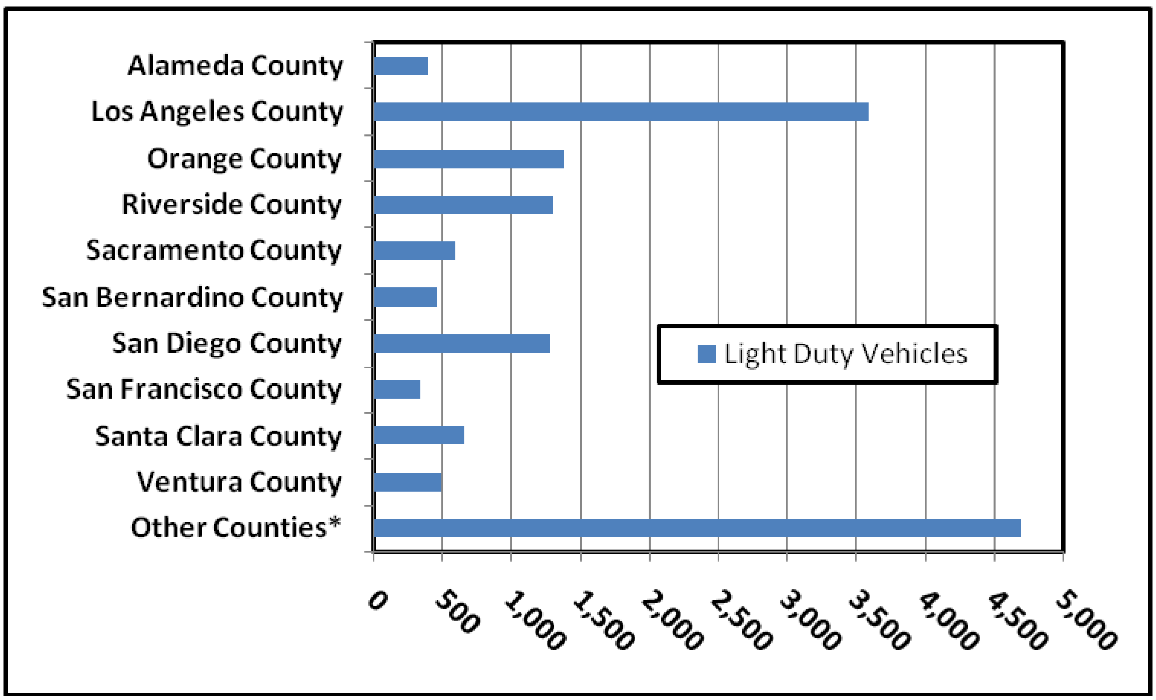
Transportation Electricity

FEVs and PHEVs have numerous benefits that make them attractive in addressing carbon reduction and petroleum dependence in the transportation sector. If the electricity used to recharge them comes from renewable or natural gas sources, they have the potential to significantly reduce GHG emissions compared to conventional petroleum-fueled vehicles. ARB places a total carbon intensity value (gCO_2e/MJ)[113] of 34.9 to 41.4 on the use of this fuel type depending on the mix of renewable fuels used in the production of the electricity. These values are adjusted to reflect the increased motor efficiency that electric vehicles exhibit and should be compared to the CaRFG-CARBOB value of 96.1 to determine full GHG reductions. These lower values in relation to gasoline are estimated by ARB to reduce vehicle emissions anywhere from 9 to 35 percent, depending on the proposed scenarios[114]. Use of substantial numbers of these vehicles would also provide air quality benefits by reducing criteria pollutant emissions compared to conventional vehicles. The cost of electricity, especially if utilities offer off-peak rates and separate meters for vehicle recharging, would be well below the cost of gasoline or diesel when factoring in engine efficiency.

Full Electric and Plug-In Hybrid Electric Vehicles

According to DMV data, there were 14,670 FEVs in operation in California in 2008. While a substantial increase over the 2,905 operating in 2001, it is substantially less than the 23,399 in operation in 2003. Since 2004 this population has remained relatively flat. Primarily, these are neighborhood electric vehicles and sub-compacts. What is the range of forecasts for their adoption? According to Southern California Edison, the utility is expecting between 400,000 and 1.6 million electric vehicles by 2020[115]. PHEVs are scheduled for mass production as early as 2010. Figure 3.43 shows the number of FEVs in operation in California in October 2008 by a selected set of counties.

Figure 3.43: Full Electric Vehicle Counts by Specific Counties, October 2008



Source: Energy Commission analysis of DMV Vehicle Registration Database

*The Other Counties category is composed of counties with less than 300 electric vehicles.

Despite their technical potential, air quality benefits, and the enthusiasm of a cadre of early adopters, electric vehicles have not been particularly successful in penetrating transportation markets. Barriers to wider-spread purchase of FEVs and PHEVs include the lack of commercially available models and delays in delivery, their higher price, and concerns about their size and range.[116] According to the 2008 CVS, relatively negative perceptions are held by many potential car buyers of FEVs, while PHEVs are viewed much more favorably. These perceptions of FEVs by potential vehicle purchasers may be intensified by a lack of familiarity with the technology and uncertainties over how the vehicles would be recharged or the expense of replacing batteries. Moreover, the infrastructure to support these vehicles is still undeveloped and the future course of development of this support is not readily apparent to consumers. At the same time, survey respondents' willingness to consider purchasing PHEVs show that, with backup conventional internal combustion technology available in a vehicle, consumers are cognizant of the economic and environmental benefits of using electricity for fuel. Consumer education will need to improve to address this lack of familiarity with electric vehicle technology.[117]

Transportation Electricity Infrastructure

Several infrastructural barriers will need to be overcome to stimulate greater penetration of electric vehicles. Utilities will have to develop procedures, standardized equipment, and rates that are conducive to the needs of vehicle users. Initially, this should probably focus on in-home recharging. Most consumers would be comfortable with home charging if time-of-use metering rates and equipment were conducive, as recharging can easily be accomplished mostly off-peak. Consumers could be further motivated if they were able to receive the carbon credits that accrued to their use of this energy source.[118]

As the vehicle population grows, the recharging system can expand to workplace and public recharging stations. Previous emphasis may have been too strongly placed on public stations[119]. Compatible and consistent standards will need to be developed for recharging connectors and other equipment, including 120/240 volt compatibility and smart chargers. Expertise and training in the installation and servicing of recharging infrastructure should be more generally available, instead of only limited to a few specialized technicians connected with electric vehicle dealers.[120]

Per the EIA[121], currently there are two battery technologies that are used in the propulsion of electric vehicles: nickel metal hydride (NiMH) and lithium-ion (Li-Ion). NiMH batteries are currently the more established technology with cheaper costs for production and established safety record, but have limited size, which limits the energy potential of this power storage method. In contrast, Li-Ion batteries have the potential to store greater amounts of energy in a lighter storage package, which increases the energy storage-to-weight ratio. Yet, costs for Li-Ion batteries to be used in electric vehicles are estimated to be as much as $30,000 for batteries that would propel a vehicle 100 miles[122]. The EIA also identifies concerns about calendar life, life cycle, and safety as additional issues that Li-Ion technology must face to improve its viability. Recharging times for these batteries are highly dependent on the voltage of the outlet that the vehicle is being plugged into. Recharging the battery can take typically 6 to 8 hours for 110 volt charging and roughly 2 hours for 240 volt charging. Public electric vehicle station could be equipped to handle 480 volt chargers, which would lower the battery re-charging time to as low as about 10 minutes, but are not currently accommodated by the standard SAE J1772 connector.[123]

With the industry identifying Li-Ion batteries as the better technology for battery production, possible supply issues with lithium could appear. Current lithium reserves have been estimated at just under than 84 million pounds, or 38,000 metric tons, in the United States. Another 410,000 tons of lithium does exist in the United States but is currently economically unfeasible to obtain. It is reported in ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1* that this could supply batteries for a total of "2.8 to 16.8 million vehicles." Using world reserves a total of approximately 273 million vehicles could be created.

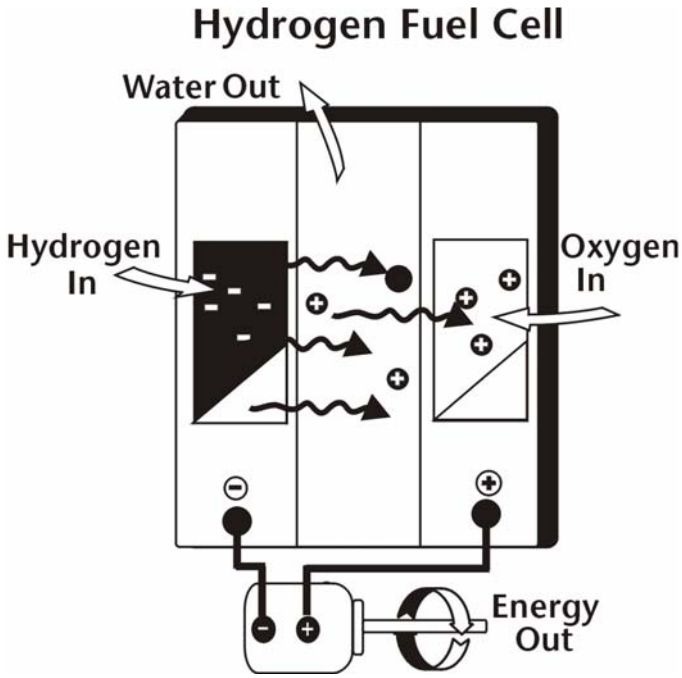
Currently, the EIA states that gas prices must be around $6 a gallon to offset the incremental costs of PHEV technology. On the positive side, the EIA in its *2009 Annual Energy Outlook* (AOE) forecasts that the cost of these batteries is expected to decline by half by 2020 and again by 2030[124].

The system impacts of expanded use of electric vehicles are also unknown and must be studied more thoroughly. While beyond the scope of this report, several questions must be answered, among them: Will large-scale adoption of electric vehicles stress the electricity production or transmission systems, especially if this adoption is focused in relatively small areas geographically? Will consumers charge off-peak? What will be the sources of the additional electricity needed for electric vehicles, and will the reliance on those sources advance air quality, carbon reduction, and energy system reliability goals?

Hydrogen Fuel Cell Vehicles

There are 400 to 500 hydrogen powered vehicles in the United States[125], with about 190 of them on the road in California[126]. These vehicles use stored hydrogen, which is combined with oxygen (from the atmosphere) through an electrochemical reaction to produce electricity, which is then used to power an electric motor (see Figure 3.44).

Figure 3.44: Diagram on the Operation of a Hydrogen Fuel Cell



Source: http://www.eia.doe.gov/kids/energyfacts/sources/IntermediateHydrogen.html

This technology is still relatively expensive due to high production costs of both fuel cells and the hydrogen, yet it is seen as an attractive technology due to its clean emissions capabilities. Currently, hydrogen storage tanks come in 350 or 700 bar variety, which relates to the storage pressure of the tank, 5or 10 million pounds per square inch (psi), respectively. Higher pressure tanks (15,000 psi / 1050 bar) are in experimental stages. Equipped with 10,000 psi / 700 bar tanks, fuel cell vehicles today can reach ranges of 200-350 miles with one fill.[127]

Natural gas is currently the primary feedstock needed for manufacturing hydrogen, but electrolysis of water can also be used, which has the potential of reducing harmful emissions from this technology to near zero levels. However, this depends on the generation of the electricity used for the process. Renewable power (for example solar) has the greatest potential to reduce the emissions to near zero. Hydrogen can also be created from renewable feedstocks such as biogas (biomethane), for instance from landfills or livestock farms to further improve its environmental profile. ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1* estimates a carbon intensity value (gCO_2e/MJ) of 33 to 62 based on various reforming processes, and these numbers should be compared to the CaRFG-CARBOB value of 96.1 to determine full GHG reductions. While hydrogen is the most plentiful gas in the universe, it is found at ground levels in only compound forms with other elements. Because hydrogen is lighter than air, it rises into the atmosphere; thus some manufacturing processes must occur to create this fuel in its elementary form.

Standards and Infrastructure

While hydrogen has many advantageous emissions qualities, hydrogen currently has no fuel quality or measurement standards for consumption and sale[128]. National and in-state standards need to be developed for fuel quality, device specifications, testing and certification methods, sampling techniques, method of sale, dispensing, and unit of measuring. Safety standards are mostly addressed in the permitting process by fire regulations.

Currently existing hydrogen stations cannot sell hydrogen at their pumps. This is due to the lack of metering systems and dispensing rules approved by California Department of Food Agriculture's (CDFA), DWM, for this purpose. Given this deficiency, California is set to be the leader in establishing hydrogen fuel standards. CDFA/DWM is working with the Society of Automotive Engineers (SAE), ASTM, and the International Organization for Standardization (ISO) to develop these specifications. The Energy Commission is also set to address this problem with CDFA in a coming interagency agreement. This agreement will be handled through the Energy Commission's Emerging Fuels and Technologies Office and is being designed to specifically solve the measurement and quality standard problem.

An additional concern is that hydrogen powered vehicles require fuel of a very high purity, which increases the cost of both the fuel and the equipment needed to produce it. For vehicle characteristics testing, NREL in Colorado is using hydrogen fuel at a purity level of 99.99 percent. Despite these hurdles and the dearth of actual vehicles, California still leads the nation in hydrogen refueling sites, with 29 of the total 62 U.S. fueling stations being in California. However, a limited number of those are currently operating and accessible to the public.

Challenges and Strategies

On the vehicle production side, Michael Coates has noted Daimler AG's commitment to the development of advanced vehicle technologies, including hybridization, battery electric, and fuel cell vehicles.[129] Currently Daimler has 100 hydrogen-powered vehicles operating in the world: 61 light-duty fuel cell vehicles, 36 Citaro buses, and 3 Sprinter vans. His testimony also indicates that the primary challenges faced by the industry include a lack of infrastructure in both fuel production and refueling, the need to develop technologies to reduce battery costs, and testing and acceptance of the vehicles by consumers. He emphasized the need for refueling infrastructure to be there when the vehicles arrive and that the stations should be focused in targeted market areas, the west sides of Los Angeles and Orange Counties being specifically mentioned. Moreover, these refueling sites must meet consumer expectations for access, convenience, and fuel quality assurance. Estimated capital costs for the construction of a refuel stations range from 1million to 5 million dollars, depending on whether on-site reforming is considered desirable.

CHAPTER 4: California Crude Oil Imports Forecast

Overview

California's 20 refineries processed more than 1.8 million barrels a day of crude oil in 2008. These facilities are the primary source of transportation fuels for California, Nevada, and Arizona. Over the next several years, the amount of crude oil required in California could remain relatively steady, although the sources of crude oil are expected to continue shifting as California's production continues to decline. However, the continual trend of increasing quantities of crude oil imports could be altered by a resumption of offshore exploration and production in California state and federal OCS waters or a cessation of California refinery expansion. The likelihood that either of these occurrences will alter the trajectory of crude oil imports over the near to mid-term period is debatable, since both would require several years of sustained effort to realize tangible results. However, over the longer term, the potential impact on crude oil imports of these two scenarios can be more significant and is presented later in this chapter for comparison.

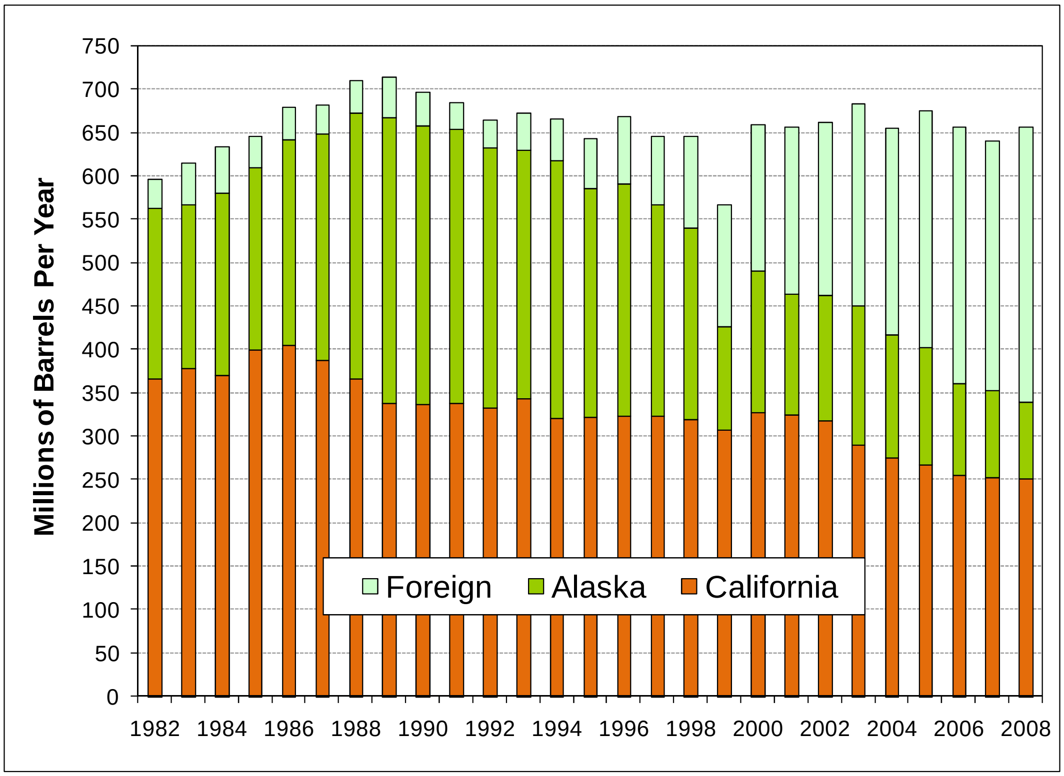
Two factors primarily determine the quantity of crude oil imported into California: the declining production from California crude oil fields and the gradual expansion of refining capacity in the state. Staff developed the forecast of crude oil imports for the state by analyzing trends for both of these factors over approximately the last decade and by making some assumptions going forward over the forecast period. Rather than working toward a single forecast, staff took the approach that a forecasted range of crude oil imports would be more useful in providing a reasonable boundary of incremental crude oil imports. This approach yielded a Low and High Case for crude oil imports.

The lower end of the forecast assumes that the decline rate of California crude oil production is less steep than the average rate of depletion experienced over the last decade. In addition, the gradual growth of California refinery capacity to process crude oil, referred to as refinery creep, is assumed to remain unchanged or flat over the forecast period. These two projections combine to yield a forecast for crude oil imports that is at the lower end of the spectrum. To develop a High Case crude oil import forecast, staff assumed that the depletion of California crude oil sources would continue at a higher rate and that the increase of refinery distillation capacity is assumed to grow at a slower rate than that observed over the last several years.

California Crude Oil Production and Import Sources

California refineries processed 656 million barrels (1.8 million barrels per day) of crude oil in 2008. The majority of this crude oil was obtained from foreign sources (48.5 percent), followed by California sources (38.1 percent), with the balance from Alaska (13.4 percent). Figure 4.1 illustrates the various sources of crude oil used in California refineries since 1982.

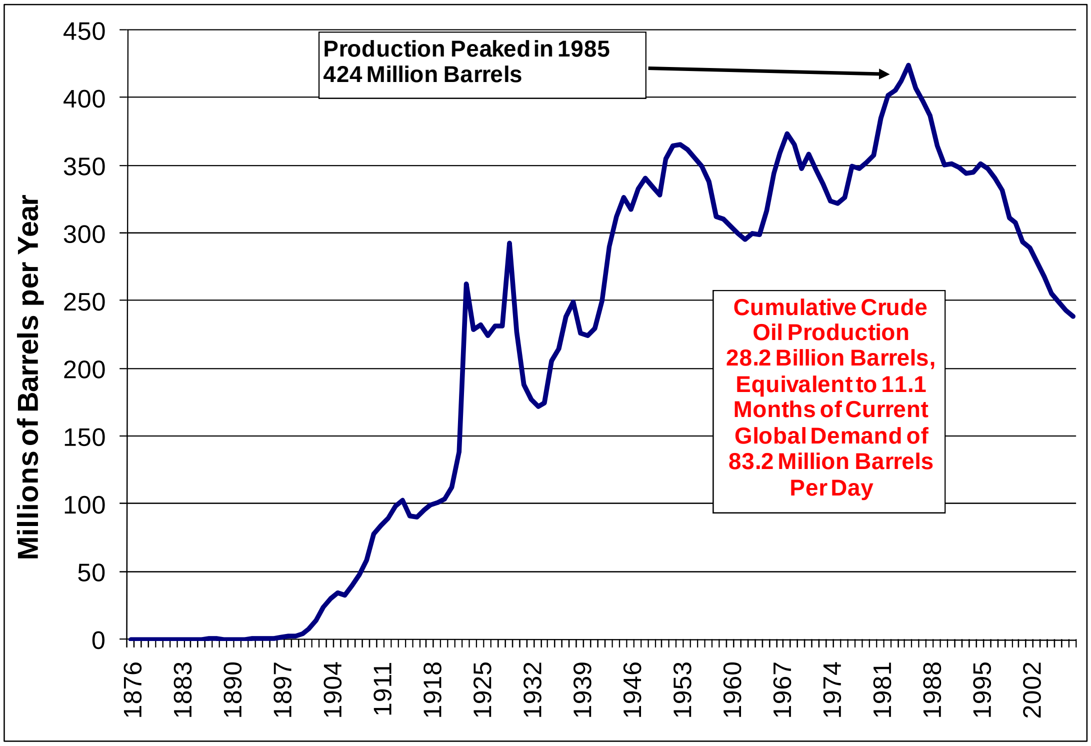
Figure 4.1: Crude Oil Supply Sources for California Refineries



Source: Annual crude oil supply data from the Petroleum Industry Information Reporting Act database

Figure 4.1 also shows that foreign sourced crude oil is increasing to displace declining quantities of California and Alaska crude oil sources. The decline of California crude oil production has continued since 1985, when crude oil production peaked at 424 million barrels per year. 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. The first oil producing well was drilled in Humboldt County near Petrolia. 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 by means of thermally enhanced oil recovery (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 results in diminishing output from wells. As Figure 4.2 illustrates, the production of California crude oil has peaked and will continue to decline over the foreseeable future. The primary question is: at what rate will California's crude oil production decline over the next 20 years?

Figure 4.2: California Oil Production (1876 to 2008)

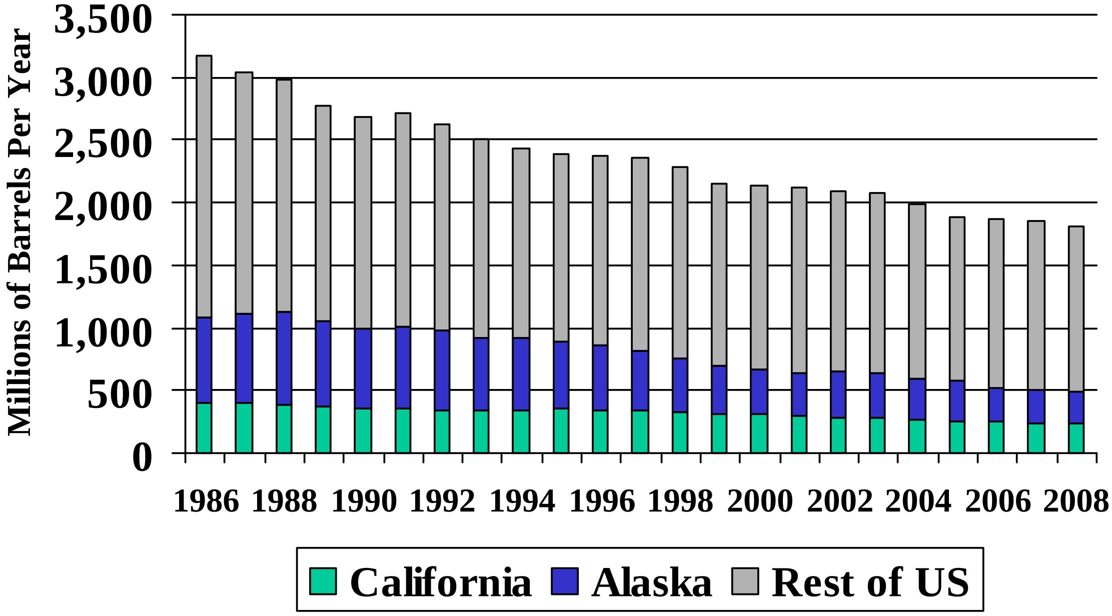


Sources: California Division of Oil, Gas, and Geothermal Resources and the California Energy Commission

U.S. Crude Oil Production Trends

Since the late 1980s, both the United States and California crude oil production have been declining at a steady pace. Since 1986, California crude oil production has declined by 41.4 percent; Alaska, by 63.2 percent; and the rest of the United States., by 36.3 percent. As of 2008, the United States crude oil production had declined to a little more than 1.8 billion barrels per year, or an average of 4.96 million barrels per day (BPD). California's annual crude oil production was approximately 238.6 million barrels during 2008, averaging 652,000 BPD. Figure 4.3 breaks down U.S. crude oil production by source between 1986 and 2008.

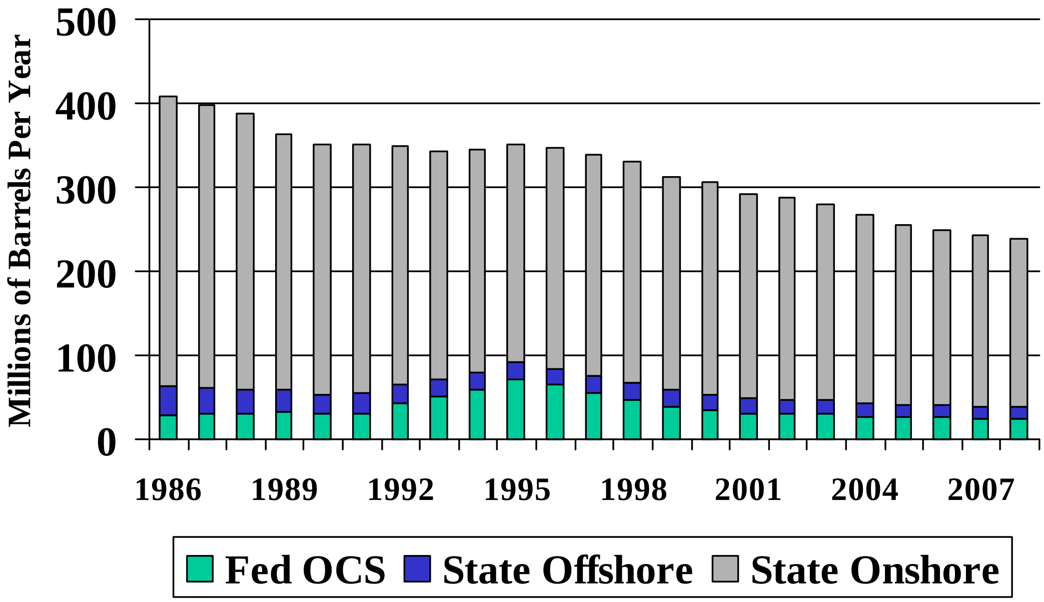
Figure 4.3: U.S. Crude Oil Production (1986 - 2008)



Sources: California Division of Oil, Gas, and Geothermal Resources, Alaska Department of Revenue, and EIA.

Figure 4.4 illustrates California's crude oil production over the same period three sources: onshore, state offshore waters, and federal OCS.[130]

Figure 4.4: California Crude Oil Production (1986 - 2008)



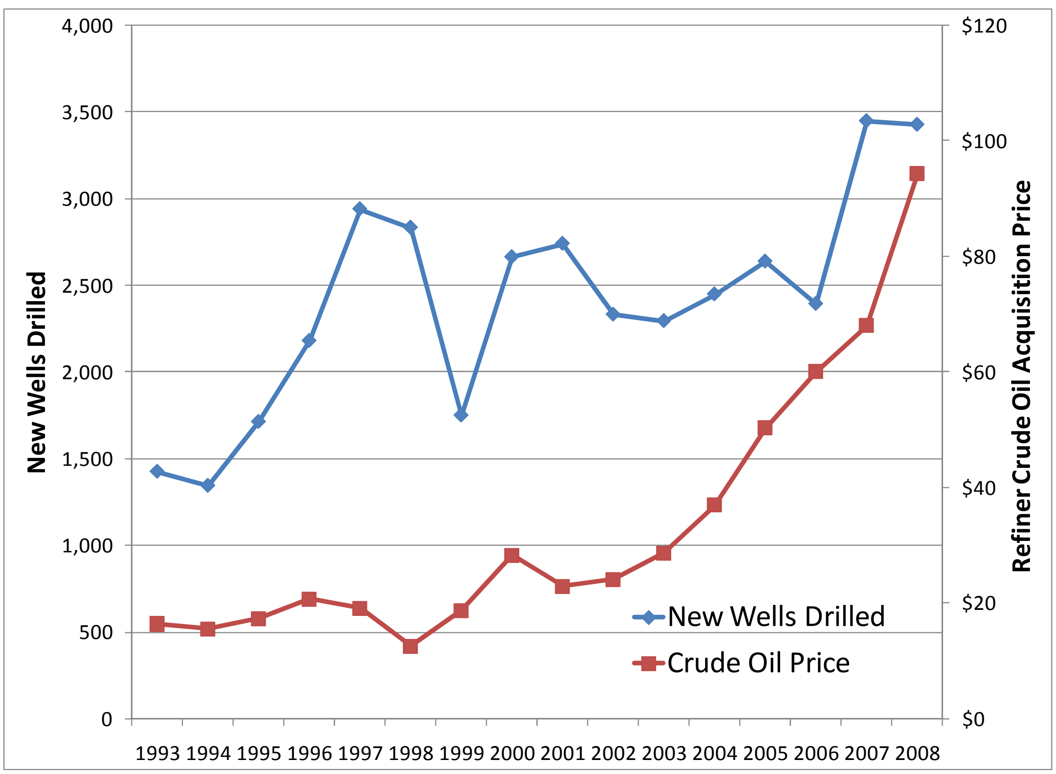
Source: California Division of Oil, Gas, and Geothermal Resource

California Crude Oil Production Decline Rates

One factor that contributes to increasing volumes of imported crude oil over time is the steady decline of California crude oil production. As local quantities of crude oil diminish, refiners must compensate by importing additional volumes from sources outside the state. Since Alaska crude oil production has declined at an even greater rate than California production, refiners must seek substitute crude oil from foreign sources.

Over the last 10 years, California's crude oil production has declined at an average rate of 3.2 percent per year. Between 2006 and 2008, the decline rate is lower, averaging 2.2 percent per year. The decreasing decline rates over the last couple of years may be in response to an increased level of drilling prompted by rising crude oil prices over the same period. Figure 4.5 illustrates the relationship between crude oil prices and increasing well drilling.

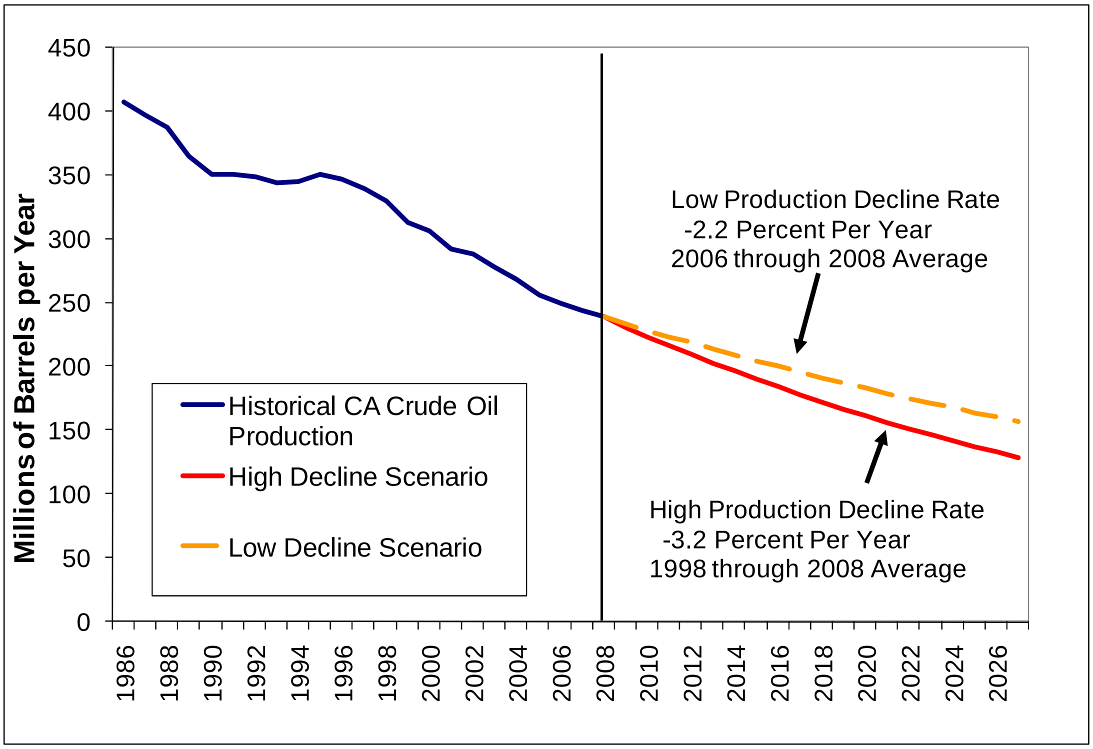
Figure 4.5: California New Wells Drilled vs. Crude Oil Price



Sources: California Division of Oil, Gas, and Geothermal Resources and the Energy information Administration

Despite the increased drilling in California over the last decade, crude oil production continues to decline, albeit at a slightly lower rate over the last couple of years. Figure 4.6 shows the historical and projected crude oil production levels based on a range of decline rates. The higher production decline rate is a trend based on the last decade of historical data. The less steep decline rate of 2.2 percent per year is based on the most recent three years of statistics.

Figure 4.6: California Crude Oil Production Forecast 2009–2030



Sources: California Division of Oil, Gas, and Geothermal Resources and the California Energy Commission

California Refinery Crude Oil Processing Capacity

In California 19 refineries are currently operating; they process an average of 1.8 million BPD of crude oil.[131] In the initial processing step, distillation process units convert crude oil to a variety of petroleum blendstocks that are combined to form gasoline, diesel, and jet fuel. Most refiners normally perform periodic maintenance at their facilities during the winter months. Occasionally, a refiner may elect to expand slightly the capacity of its crude oil distillation equipment if the project meets environmental guidelines and can be justified as having a sufficient economic return for the cost of the project. This gradual increase of distillation capacity—refinery creep—is the second primary factor that can contribute to increasing imports of crude oil for California.

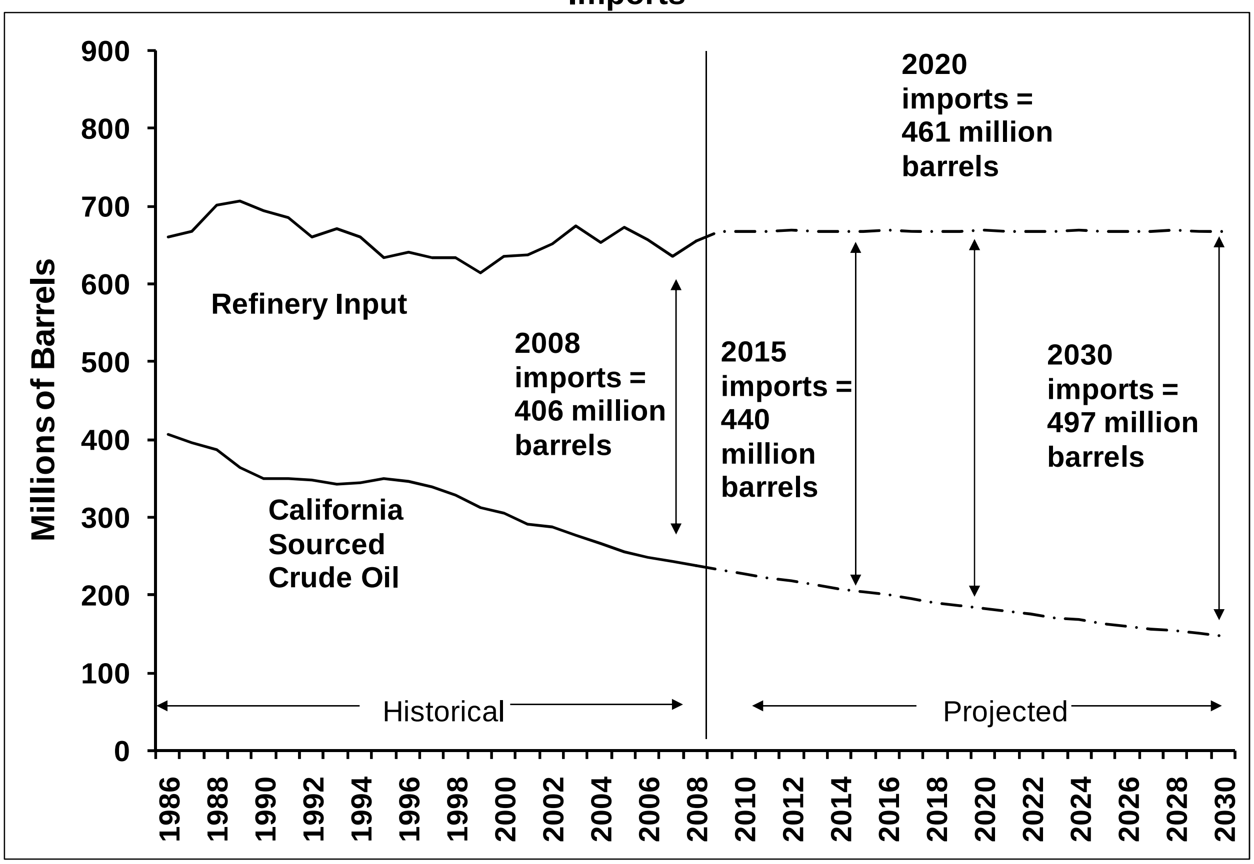
Between 2001 and 2008, California refinery creep for crude oil distillation capacity increased at an average rate of 0.84 percent per year. Between 2003 and 2008, the refinery creep rate was a little more than half that level at 0.45 percent per year. Staff selected the lower crude oil distillation capacity growth rate for calculating the High Case for crude oil imports. Staff has elected to use a flat distillation capacity growth rate of zero percent per year over the forecast period for calculating the Low Case crude oil imports. The primary reason for use of a flat rate is the lower gasoline demand forecasts that have resulted from improved fuel economy standards and increased mandated levels of renewable fuels. Further, the U.S. EIA has also forecast in its Reference Case a refinery distillation capacity growth rate in the western region of the United States (referred to as Petroleum Administration for Defense District V or PADD V) that is nearly identical (0.47 percent) over the same forecast period.[132] These two distillation capacity growth rates bounded the lower and upper limits of refinery creep for this analysis.

Since refineries do not process crude oil when the distillation units are undergoing maintenance or are temporarily out of service from an unplanned refinery outage, their utilization rates (a measure of crude oil processed per day relative to the maximum capacity of the equipment) will be at a level of less than 100 percent. For all of the refineries operating in California since 1999, the combined utilization rate has averaged 89.9 percent. For this work, staff assumed that this utilization rate would remain constant over the next 21 years.

Crude Oil Import Forecast

To estimate a range of incremental crude oil imports for California, staff compared the trends of crude oil production decline rates and gradual refinery distillation capacity growth to produce a Low and High Case forecast. Figure 4.7 depicts the Low Case.

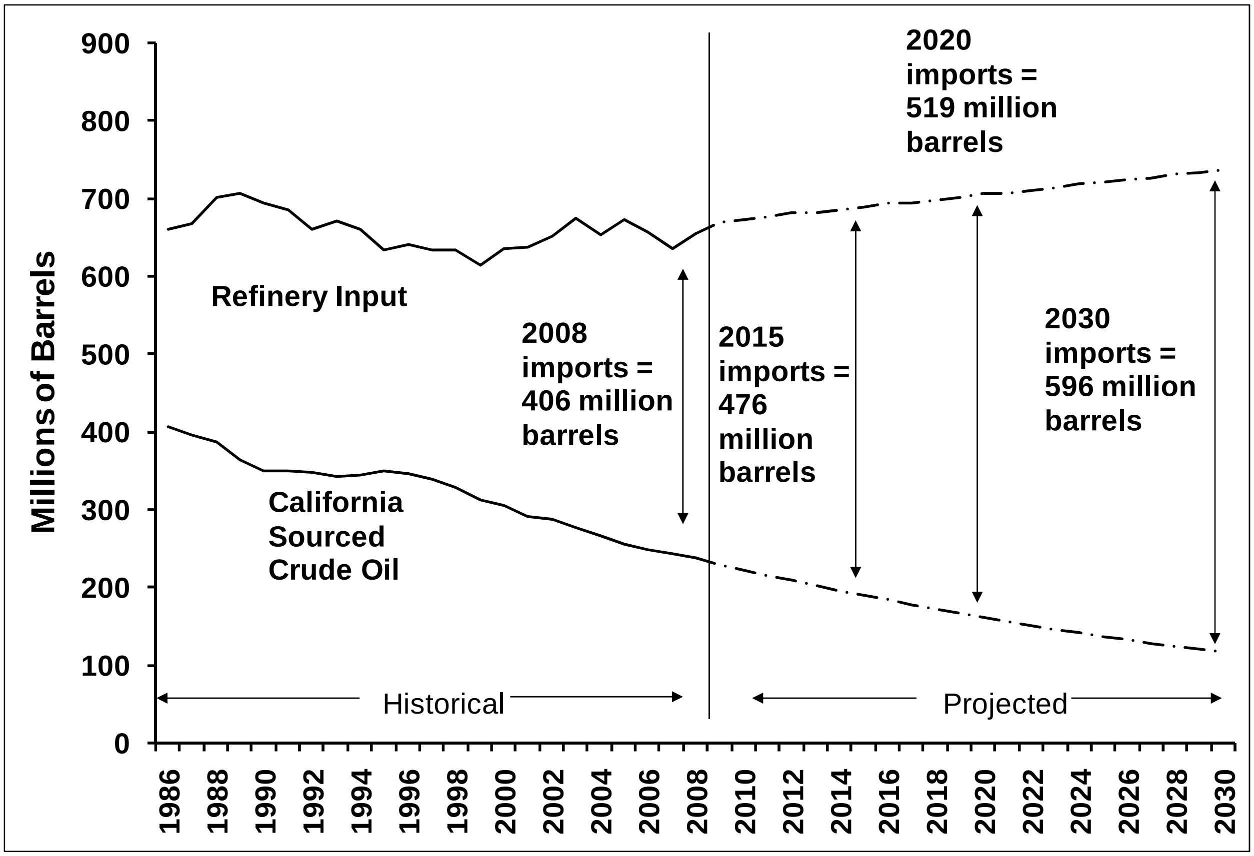
Figure 4.7: Low Case Forecast for California Crude Oil Imports



Sources: California Energy Commission analysis and Petroleum Industry Information Reporting Act database

Under the Low Case projection, annual crude oil imports are forecast to increase by 34 million barrels between 2008 and 2015 (8.5 percent increase), by 55 million barrels by 2020 (13.6 percent increase), and by 91 million barrels by 2030 (22.5 percent increase compared to 2008). To obtain these projections, staff assumed that distillation capacity increases (refinery creep) would be at the lower rate of zero percent per year, while the decline rate of California crude oil production would be at the lower rate of 2.2 percent per year. Using higher rates for both crude oil production decline and refinery creep, crude oil imports are expected to grow faster. Under the High Case projection, annual crude oil imports rise by 70 million barrels between 2008 and 2015 (17.3 percent increase), by 113 million barrels by 2020 (28.0 percent increase), and by 190 million barrels by 2030 (47.0 percent increase compared to 2008). Figure 4.8 illustrates the High Case projection for California crude oil imports.

Figure 4.8: High Case Forecast for California Crude Oil Imports



Sources: California Energy Commission analysis and Petroleum Industry Information Reporting Act database

As each of the two previous figures indicates, the use of different rates for crude oil production decline and refinery creep can significantly alter the estimated range of incremental crude oil imports. Table 4.1 combines the various rates into a single table for both the mid-term (2020) and longer-term (2030) periods of the forecast.

Table 4.1: Import Projections for Entire State

Incremental California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Low Rate of Crude Oil Decline - 2.2%			High Rate of Crude Oil Decline - 3.2%		
	2015	2020	2030	2015	2020	2030
Zero Percent	35	55	91	49	77	122
0.45 Percent	56	92	160	70	114	191

Source: California Energy Commission

The next step in the analysis involved an estimate of the portion of the incremental crude oil imports for the entire state that would be delivered to Northern and Southern California, respectively. Based on recent historical trends, staff assumed that 60 percent of the incremental crude oil imports over the forecast period would be delivered to marine terminals in Southern California, with the balance (40 percent) handled by marine berths in the San Francisco Bay Area.[133] Table 4.2 shows how the incremental import projections for Southern California can vary by changing the assumed rates for crude oil production decline and refinery creep.

Table 4.2: Import Projections for Southern California

Incremental Southern California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Low Rate of Crude Oil Decline - 2.2%			High Rate of Crude Oil Decline - 3.2%		
	2015	2020	2030	2015	2020	2030
Zero Percent	21	33	55	29	46	73
0.45 Percent	33	55	96	42	68	114

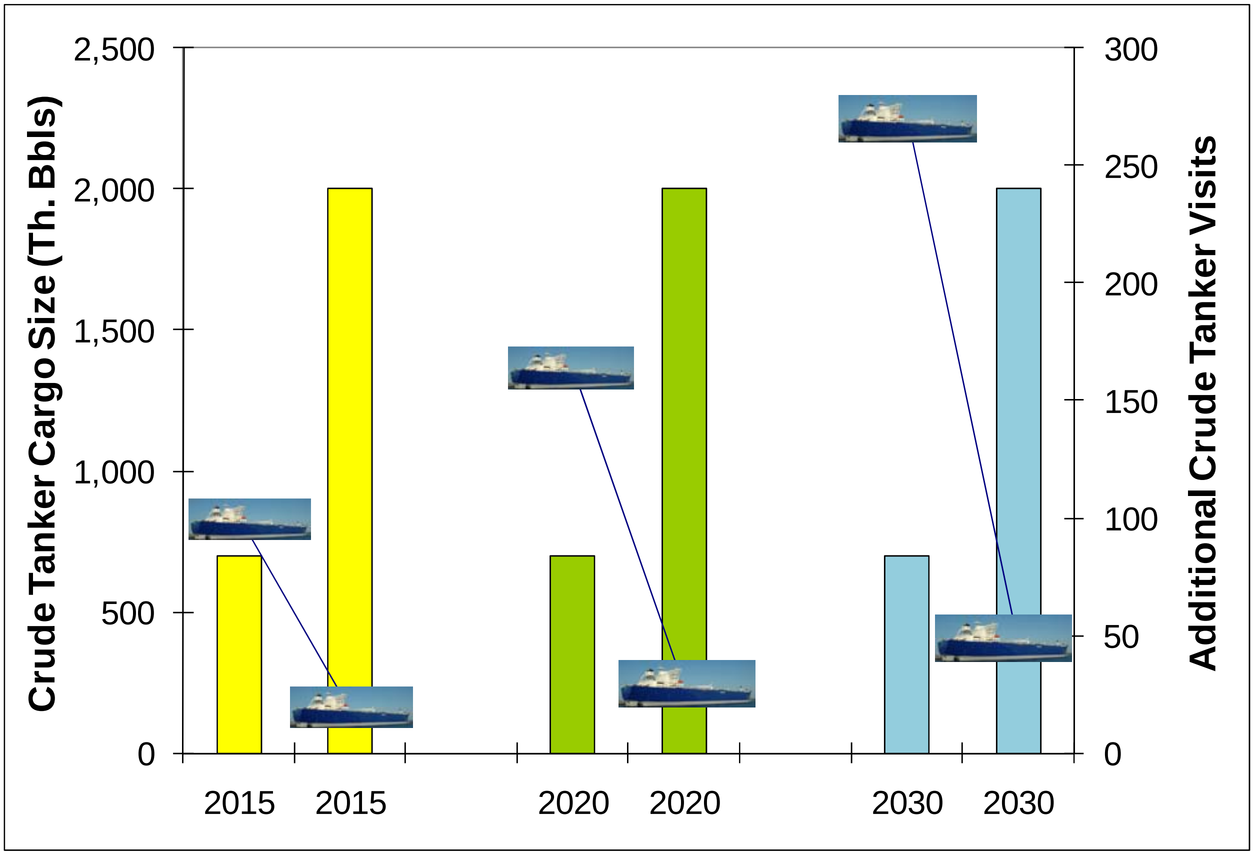
Source: California Energy Commission

Crude Oil Tankers – Incremental Voyages

The increased imports of crude oil are expected to result in a greater number of marine vessels (referred to as crude oil tankers) arriving in California ports. Staff has examined recent import information to determine an average cargo size per crude oil tanker import event. For calculating additional crude oil tanker trips, staff used an upper limit of 2 million barrels of cargo capacity per import event and a lower limit of 700,000 barrels capacity. The upper limit represents the storage capacity of a very large crude carrier (VLCC). The lower range is the capacity of typical foreign crude oil tankers, referred to as Aframax (80 thousand to 119 thousand deadweight tonnage). This scenario assumed that the bulk of the incremental imports of crude oil over the near term will originate from foreign sources and be transported on Aframax marine vessels.

Using these two estimates for crude oil tanker capacity, staff calculated 17 to 100 additional crude oil tanker arrivals per year by 2015, 28 to 162 by 2020, and 46 to 272 additional arrivals per year by 2030. The broad range for the estimate is a consequence of the large difference in capacity between the Aframax and VLCC storage capacities, as well as the annual incremental crude oil import forecast differences between the High and Low cases.[134] Figure 4.9 depicts the broad range of incremental crude oil tanker import events at various points of the forecast. The vertical axis on the left side is for the size of the crude oil tanker cargo capacity, while the vertical axis on the right side is for the number of additional crude oil tanker visits in a specific year at some point during the forecast period.

Figure 4.9: Incremental Crude Oil Tanker Visits



Source: Energy Commission staff analysis of forecast and crude oil tanker attributes.

Crude Oil Storage Capacity–Anticipated Growth

The importation of incremental volumes of crude oil will not only necessitate an increased number of crude oil tanker visits, but will also require a larger storage tank capacity for the marine facilities receiving the additional cargoes. The Energy Commission staff has calculated additional storage tank capacity that would have to be constructed to handle the incremental imports of crude oil. This scenario assumes that most of the existing marine terminals are at or near maximum operating capacity. Two incremental storage tank throughput rates were used to calculate the additional crude oil storage tank capacity estimates. The first rate uses a design capacity throughput similar to the proposed crude oil import project at Pier 408 in San Pedro

Harbor, approximately 1 million barrels of storage capacity per 23 million barrels of imports per year.[135] The second rate assumes a slower cycling of the storage tanks, yielding a conversion rate of about 1 million barrels of storage capacity per 12 million barrels of imports per year. Based on these assumptions, the incremental crude oil storage capacity needed in California would amount to between 1.5 million and 5.8 million barrels by 2015; between 2.4 million and 9.5 million barrels by 2020; and between 4.0 million and 15.9 million barrels of storage capacity by 2030. Nearly 60 percent of this incremental storage capacity will need to be constructed in Southern California, where spare land capacity for such projects is at a premium.

Alternative Assumptions – Impact on Crude Oil Import Forecast

Crude oil imports for California refiners could be less than initial staff projections indicate under a different scenario: expanded exploration and production off of California's coast. Expanded offshore drilling and production are a contentious issue that has received increased interest due to recent federal and state activities.

Timing and Supply Potential of Expanded Offshore Drilling Scenario

The federal moratoria for drilling in federal OCS waters expired when Congress took no action to reinstate the ban before the new federal fiscal year began on October 1, 2008. Before that date, the Minerals Management Services (MMS) initiated a new five-year lease process that included the moratoria OCS areas. The moratoria areas off the coast of California are estimated by MMS to contain between 5.8 billion and 15.8 billion barrels of Undiscovered Technically Recoverable Resources (UTRR) crude oil.[136] Over half of this estimated crude oil resource is located in federal waters off the coast of Southern California. However, the federal MMS estimates that between 53 and 78 percent of these reserves would be economically recoverable based on crude oil prices ranging from $60 to $160 per barrel.[137]

Prior to development of any of the moratoria OCS areas there are two discrete steps that must be undertaken: development of a five-year program; and planning for a specific sale. *Together, these processes can take between 3.5 and 5 years to complete, absent any intervening litigation which would extend the timeline***.** These two MMS regulatory processes are briefly described below.

Once an oil company is a successful recipient of a lease, it would be able to initiate the processes of developing an exploration plan, obtain the necessary capital, construct the drill rigs, drill exploratory wells, assess drill results and mapping analysis, construct a drilling platform, drill production wells, and construct pipelines from the platform to onshore facilities before new crude oil production could begin.

Due to the lengthy federal regulatory process and the numerous developmental steps, it is no surprise that the U.S. EIA estimates that it could take up to 10 years for new crude oil production to begin from the moratoria OCS areas.[138]

Developing a Five-Year Program

The preparation of the schedule for the OCS oil and natural gas lease sales is governed by Section 18 of the Outer Continental Shelf Lands Act (OCSLA), which was added to the Act in 1978. Section 18 of the OCSLA requires the Secretary of the Interior to prepare and maintain an OCS oil and natural gas leasing program.

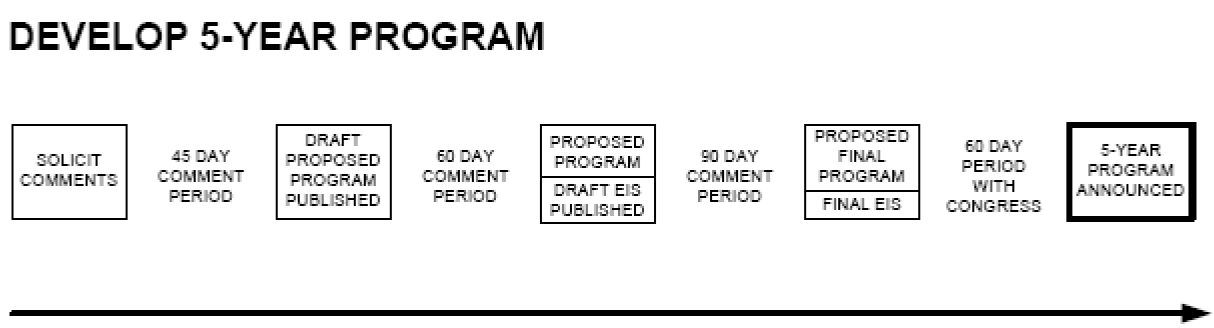
When approved, the leasing program consists of scheduled lease sales for a five-year period, along with policies pertaining to the size and location of sales and the receipt of fair-market value. The schedule indicates the timing and location of sales and shows the presale steps in the process that lead to a competitive sealed bid auction for a specific OCS area. In preparing a new five-year program, the Secretary solicits comments from coastal state governors and localities, tribal governments, the public, the oil and natural gas industry, environmental groups, affected federal agencies, and the Congress.

The MMS requests comments at the start of the process of developing a new program and following the issuance of each of the first two versions:

- The draft proposed program with a 60-day comment period:
- The proposed program with a 90-day comment period.

The third and last version, the proposed final program, is prepared with a 60-day notification period following submission to the President and Congress. After 60 days, if Congress does not object, the Secretary may approve the program.

The entire five-year lease program process takes from 18 to 36 months to complete.

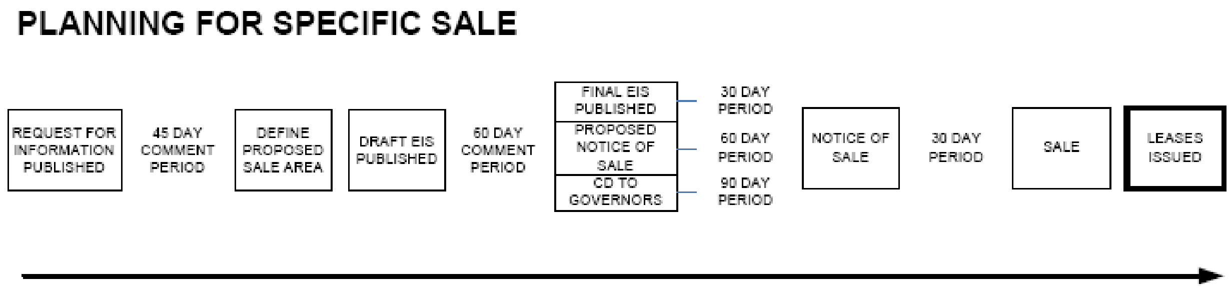


On July 30, 2008, MMS announced that it was initiating a new five-year process.[139] The **Draft Proposed 5-Year OCS Oil and Gas Leasing Program for 2010-2015** has been released and comments are due September 21, 2009.

Planning for a Specific Sale

After adoption of a five-year leasing program, the usual first step in the sale process for an area is to publish simultaneously in the Federal Register a Call for Information and Nominations (Call) and a Notice of Intent (NOI) to prepare an environmental impact statement (EIS). Comments are usually due 45 days after the Call and NOI are published. Some proposed sale areas may include an additional first step—a request to industry to solicit comments and interest in the specific area.

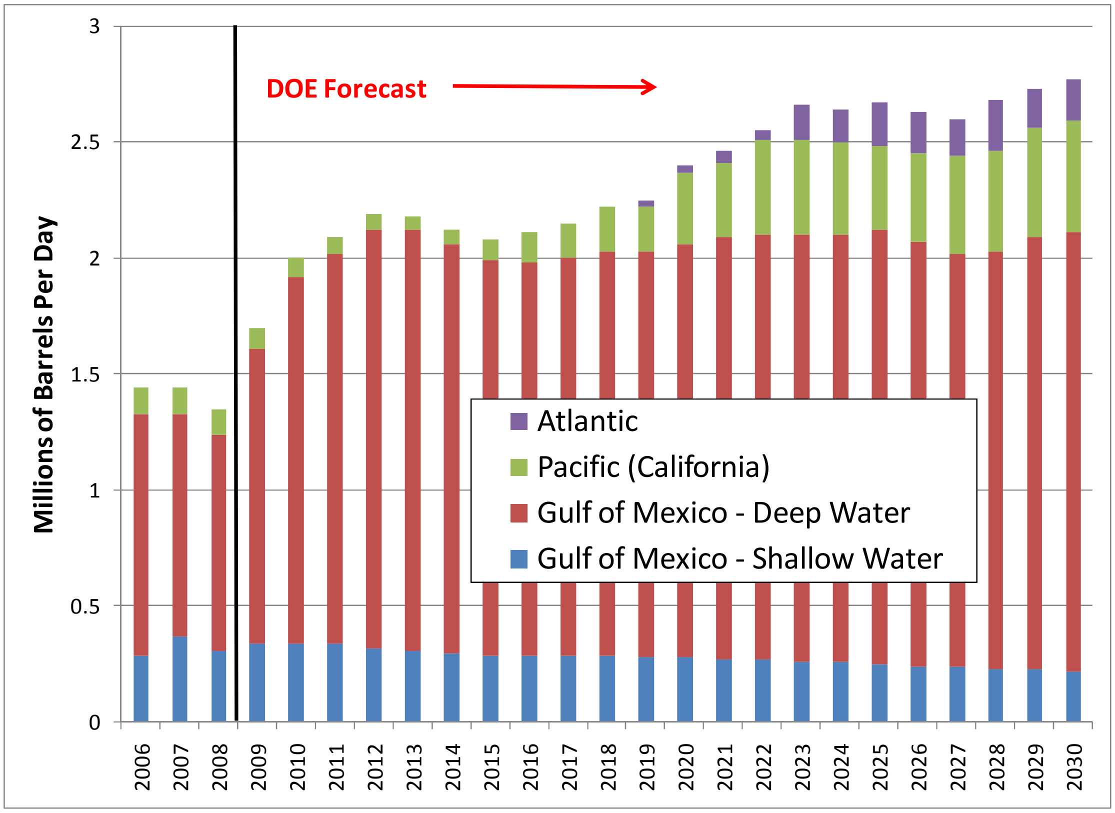
The process from the Call/NOI to the sale may take two or more years.



The U.S. DOE has estimated the pace and quantity of additional crude oil production that could be achieved from expanded drilling in federal OCS waters for the lower 48 states. The incremental quantities are illustrated in Figure 4.10. Under this scenario, OCS crude oil production is forecast to increase from 1.35 million barrels per day in 2008 to approximately 2.77 million barrels per day by 2030. New production associated with lifting of the moratoria is assumed to begin in 2015, since the process to develop these new areas could require at least five years (see discussion above). Compared to 2014, crude oil production would increase from 2.12 million barrels per day to 2.77 million barrels per day by 2030, a higher level of approximately 650,000 barrels per day by the end of the forecast period. The majority (65 percent by 2030) of this incremental OCS crude oil production is forecast by the U.S. DOE to occur in the Pacific region (essentially California). In fact, nearly 74 percent of the cumulative incremental crude oil production is forecast to originate from the Pacific (California) OCS region, 1.5 billion barrels of the total 2.1 billion barrels incremental crude oil production between 2014 and 2030.

If such an expanded drilling scenario were to be pursued by federal, state, and local governments, a new infrastructure of offshore oil production platforms, interconnecting pipelines, crude oil trunk lines, and pump stations would likely be required to achieve this forecast level of incremental crude oil production. It is unknown what portion of the untapped economically recoverable crude oil OCS reserves are close to any of the existing 22 offshore platforms (in federal OCS waters) such that directional drilling could be employed to increase production without constructing any new platforms and associated infrastructure.[140] However, it is unlikely that these OCS crude oil reserves could be completely accessed without the construction of new infrastructure that is currently undetermined in scope and cost.

Figure 4.10: OCS Crude Oil Production Forecast – No Moratoria



Source: Energy Commission staff analysis of data from the Department of Energy, Office of Petroleum Reserves

Impact on California Crude Oil Import Forecast of Lifting OCS Moratoria

If the lifting of the OCS moratoria remains in effect and development proceeds as forecast by U.S. DOE off the coast of California, the incremental crude oil production could have a significant impact on the forecast of crude oil imports, as illustrated in Table 4.3.

Table 4.3: Moratoria Scenario – Import Projections for Entire State

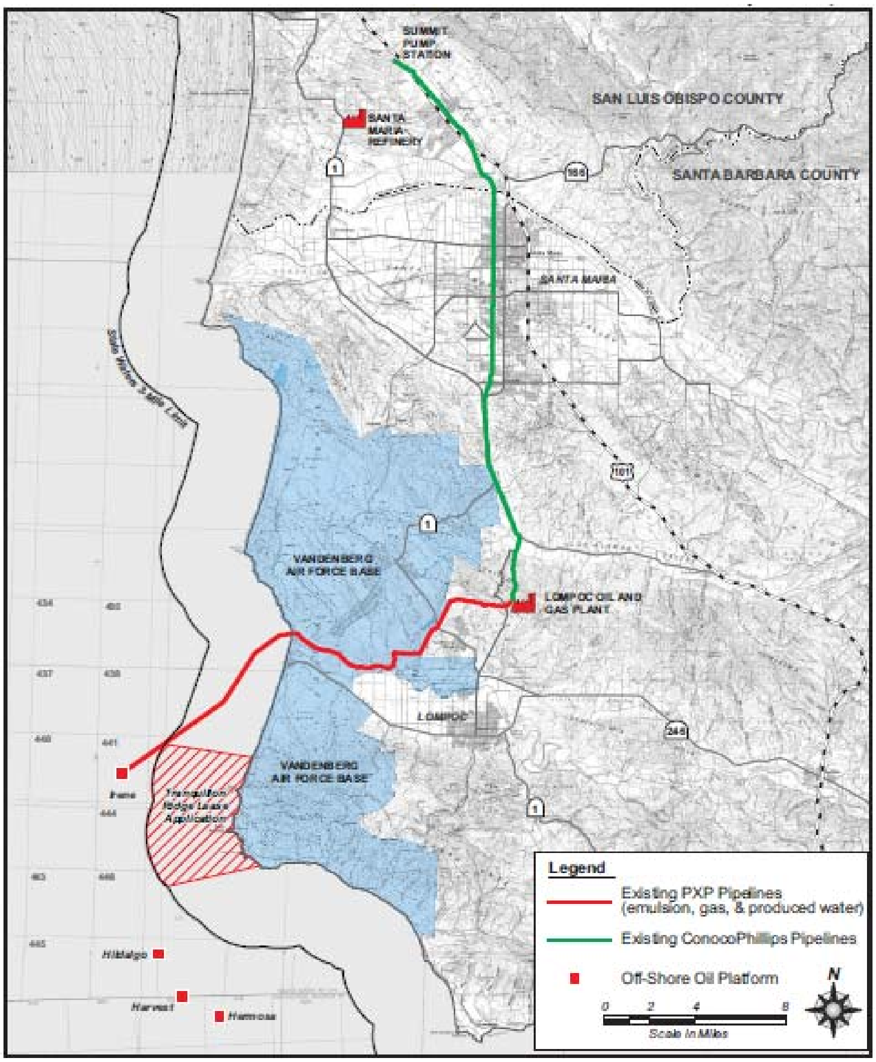
Incremental California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Low Rate of Crude Oil Decline - 2.2%			High Rate of Crude Oil Decline - 3.2%		
	2015	2020	2030	2015	2020	2030
Zero Percent	24	-36	-62	38	-14	-32
0.45 Percent	45	1	7	59	22	37

Source: California Energy Commission

Impact on California Crude Oil Import Forecast of Tranquillon Ridge Project

Although the scenario of expanded drilling off of California's coast in OCS waters is a contentious and complicated process that would entail a significant period to achieve any tangible results (if allowed to proceed), there is another effort underway off the coast of California that could result in additional quantities of crude oil being produced from an existing offshore platform. The Plains Exploration and Production Company project involves drilling of additional wells from itsexisting Platform Irene (that lies in federal OCS waters off of Vandenberg Air Force Base) into a crude oil field referred to as Tranquillon Ridge (Figure 4.11).

Figure 4.11: Tranquillon Ridge Project Location



Source: County of Santa Barbara Planning and Development, Final EIR, Figure 2-1, page 2-29, April 2008

There are four distinct differences between the proposed Tranquillon Ridge Project and the expanded offshore drilling in OCS waters scenario:

- Scope of potential incremental production is significantly less.
- Timing to initiate new production is more rapid.
- No need for new offshore platforms and associated infrastructure.
- Sunset of activities.

The federal OCS expanded drilling scenario is estimated to result in an increase of federal OCS crude oil production of 200,000 BPD by 2020 (versus 2008), as compared to an estimate of between 8,000 and 27,000 BPD from the Tranquillon Ridge Project.[141] The Tranquillon Ridge Project is assumed to achieve new crude oil production within a year of renewed drilling activity from existing Platform Irene. Assuming the project is granted permission to move forward sometime later in 2009, new production could begin in late 2010 or early 2011.[142] Expanded drilling off the coast of California in federal OCS waters would require far more time to begin new crude oil production, estimated at the earliest by 2015. Finally, there is a provision in the Tranquillon Ridge Project agreement to sunset operations by 2024. There are no such proposals or requirements being considered at this time for the new five-year lease program being developed by MMS for expanded drilling in federal OCS waters.

Other Issues Related to Crude Oil Infrastructure

A California Strategic Petroleum Reserve (SPR) for crude oil was a topic raised during IEPR proceedings earlier this year. The subject of strategic storage of crude oil in California as a means to provide crude oil to refineries in the event of a supply disruption is also a concept that was previously discussed during the *2007 IEPR* proceedings. At that time, the Office of Petroleum Reserves (a U.S. DOE agency) was examining potential alternative sites for placement of strategic crude oil inventories that would be beneficial during a crude oil supply disruption episode associated with a temporary loss of a portion of the crude oil import infrastructure (due to either a significant natural disaster or intentional act of sabotage) or a temporary loss of supply from a particular source location or country.

Currently, there are no plans by U.S. DOE to create an SPR West Coast expansion. Although staff believes that the placement of crude oil in California could decrease the likelihood of refinery production decline in the event of a temporary loss of crude oil deliveries, there has been no engineering analysis performed to date for quantifying an estimated range of cost for such a project.

CHAPTER 5: California Petroleum Products Imports Forecast

Overview

The effects of trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states determine the rate at which California's imports of transportation fuels will increase during the forecast period. This section contains a discussion of the specific factors that staff assessed, the methodology employed when conducting the analysis, and a description of additional factors that can increase the level of uncertainty inherent in this work. The primary purpose of this analysis is to quantify a range of incremental imports of transportation fuels for the regional market and to identify any potential constraints within the distribution infrastructure that could impede supplies of transportation fuels for California consumers and businesses.

The global and domestic economic downturn over the last 12+ months, coupled with rising fuel costs that culminated in the tremendous crude oil price spike of 2008, has contributed to a multi-year decline in transportation fuel demand that was last experienced during the late 1970s.[143] This significant development has reduced imports of petroleum products and even partially contributed to the closure of a California refinery and idling of nearly all of California's ethanol facilities. Increased use of renewable fuels that will result from recently adopted federal and state mandates, along with increased vehicle average fuel efficiency, are forecast to negatively impact the growth of traditional petroleum-based transportation fuels over the next 20 years. Some of these expected changes to long-standing trends could be rather significant, potentially signaling the passage of a peak for California petroleum transportation fuel demand and imports of refined petroleum fuels.

California Refinery Production Capacity

Over the last several years, production of transportation fuels from California refineries has not normally kept pace with consumer demand, resulting in greater quantities of imported gasoline, diesel, jet fuel, and alternative fuels. However, over the last couple of years the need for imports has lessened as demand for traditional transportation fuels (gasoline, diesel and jet fuel) has declined by 6.2 percent since 2007.[144] The level of transportation fuel imports over the forecast period can be influenced by the rate at which refinery capacity grows over time. Production of transportation fuels is dependent on:

- Maximum capacity to process crude oil (distillation capacity)
- The number of days refineries operate at normal rates during the year (utilization rate)
- Maximum capacity to process additional refinery feedstocks (process unit capacity)

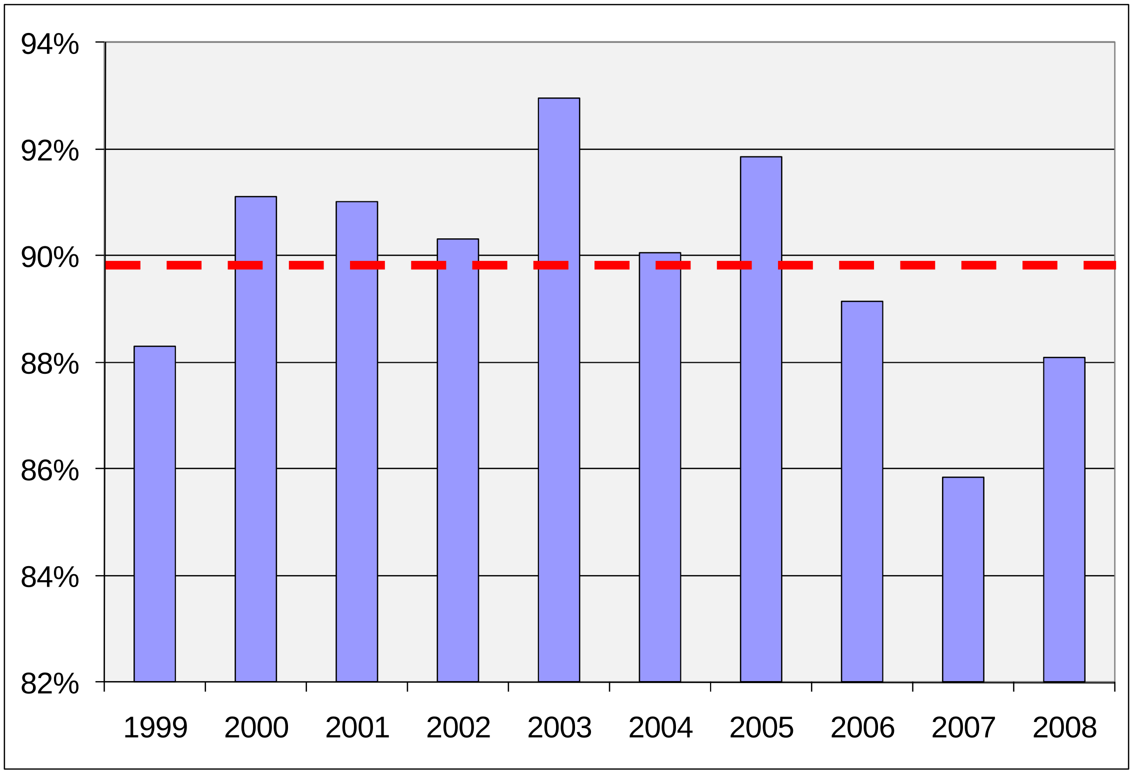
Crude Oil Processing (Distillation) Capacity

If California refineries process additional quantities of crude oil each year, the output of petroleum products from those refineries should be greater. The gradual growth of California refinery capacity to process crude oil, referred to as refinery creep, is assumed to grow at a slower rate than that observed over the last several years. In California 19 refineries are currently operating; they process an average of 1.8 million BPD of crude oil.[145] In the initial processing step, distillation process units convert crude oil to a variety of petroleum blendstocks that are combined to form gasoline, diesel, and jet fuel. Most refiners normally perform periodic maintenance at their facilities during the winter months. Occasionally, a refiner may elect to expand slightly the capacity of its crude oil distillation equipment if the project meets environmental guidelines and can be justified as having a sufficient economic return for the cost of the project.

Between 2001 and 2008, California refinery creep for crude oil distillation capacity increased at an average rate of 0.84 percent per year. Between 2003 and 2008, the refinery creep rate was a little more than half that level at 0.45 percent per year. Staff selected the lower crude oil distillation capacity growth rate for purposes of calculating the Low Case for transportation fuel imports. Staff has elected to use a distillation capacity growth rate of zero percent per year over the forecast period for purposes of calculating the High Case for transportation fuel imports. Further, the U.S. EIA has also forecast in their Reference Case a refinery distillation capacity growth rate in PADD V that is nearly identical (0.47 percent) over the same forecast period.[146] These two distillation capacity growth rates were used as part of the analysis to estimate the lower and upper limits of transportation fuel imports.

Since refineries do not process crude oil when the distillation units are undergoing maintenance or are temporarily out of service from an unplanned refinery outage, their utilization rates (a measure of crude oil processed per day relative to the maximum capacity of the equipment) will be at a level of less than 100 percent. For all of the refineries operating in California since 1999, the combined utilization rate has averaged 89.9 percent. For purposes of this work, staff assumed that this utilization rate would remain constant over the next 21 years. It should be noted that the use of a constant crude oil processing capacity would increase the transportation fuel import forecast. The potential import impact of this scenario is discussed later in this chapter. Figure 5.1 depicts annual and average crude oil distillation utilization rates over the last decade.

Figure 5.1: California Refineries – Crude Oil Utilization Rates (1999-2008)



Sources: PIIRA and CEC analysis.

Process Unit Capacity Growth

California refineries use other types of equipment to further refine the crude oil initially processed by the crude oil distillation units. These process units can also be used to convert refinery feedstocks, purchased from outside the refinery, into petroleum blendstocks suitable for creating gasoline and other transportation fuels. Over the forecast period, the process unit capacity is expected to increase at a rate that will be sufficient to accommodate the additional feedstocks generated by the continuously expanding crude oil distillation process capacity.

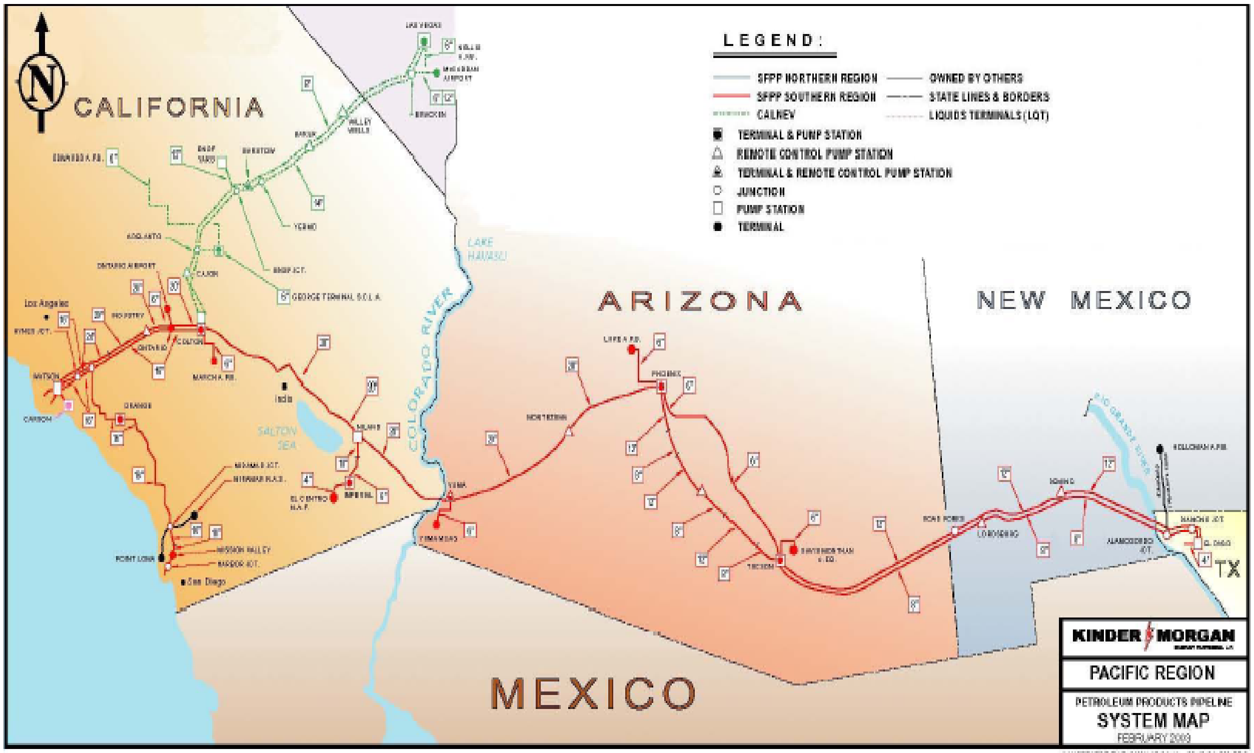
Exports of Transportation Fuels to Neighboring States

Nevada and Arizona do not have any refineries that can produce transportation fuels. As a consequence, these states must import all of the transportation fuels that they consume from refineries located outside their borders. Refineries located in California export petroleum products via pipelines that are linked to distribution terminals located in Reno, Las Vegas, and Phoenix. This network of interstate pipelines is owned and operated by the Kinder Morgan Pipeline Company (KMP).

Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. In 2006, approximately 55 percent of Arizona's demand was met by products exported from California. However, that percentage dropped to just 35 percent by

2008 as refiners and other marketers shifted source of supply away from California and over to Texas and New Mexico. The larger balance of transportation fuels consumed in Arizona is now delivered in a petroleum product pipeline that originates in Western Texas on a section of the KMP system referred to as the East Line. Figure 5.2 depicts the KMP petroleum product pipeline system in the Southwest United States.

Figure 5.2: Kinder Morgan Interstate Pipeline System



Source: Kinder Morgan Pipeline company.

If expansion of California refinery capacity fails to keep pace with demand growth for transportation fuels in California, Nevada, and Arizona, imports of petroleum products and alternative fuels will grow over time. Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account East Line expansion plans, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market.

A variety of different analytical approaches were employed to develop transportation fuel demand forecast for Arizona and Nevada. The latest forecasted growth of commercial passenger jet activity by the FAA was used to obtain an estimate for jet fuel demand for Arizona and Nevada.[147] It should be noted that only one base case jet fuel demand forecast was developed for Arizona and Nevada, rather than Low and High demand assessments.

Diesel fuel demand for the neighboring states was estimated using specific cases from the *2009 Annual Energy Outlook (AEO)* forecast by the U.S. EIA for the Mountain census region of the

United States.[148] The Low Demand Case used the Updated Reference Case growth projections for transportation diesel fuel in the Mountain Region.[149] This particular scenario from U.S. EIA would be considered a High Oil Price case. The rate of growth for diesel fuel from this U.S. EIA scenario was applied to the 2008 starting point in both states to obtain a forecast for total diesel fuel demand. The High Demand case for diesel fuel in the neighboring states was derived by using the Low Oil Price scenario from U.S. EIA's *2009 AEO*.[150] Once again, the forecast under this scenario for the Mountain census region was used to determine a rate of demand that was applied to the same 2008 starting point for each of the two states.

The gasoline demand forecasts for Arizona and Nevada used the same approach as that employed for diesel fuel. However, as was the case with the California gasoline demand calculations, these initial forecasts had to be revised to reflect the additional use of renewable fuel (mainly ethanol) that is part of the mandated requirements of the federal RFS2. Fair share volumes of biofuels were first calculated for Arizona and Nevada, followed by a rebalancing of the gasoline demand forecast to compensate for the additional quantity of ethanol associated with RFS2 compliance. For purposes of calculating forecasted quantities of E85, maximum ethanol concentration in Arizona and Nevada was assumed to be 10 percent by volume (just like California) over the forecast period. The U.S. EPA is scheduled to rule some time later this year whether or not the ethanol blending limit can increase to 15 percent by volume. If so, it is recognized that the volumes of E85 forecast in Arizona and Nevada could be less than indicated by this analysis. However, it is unknown to what extent E15 blends would be permissible in the neighboring states. This is especially the case with Arizona given that state's Cleaner Burning Gasoline (CBG) regulations.

Table 5.1 provides historical and forecasted quantities of transportation fuels for Arizona. Gasoline demand under the Low Case is nearly flat over the forecast period and E85 sales grow significantly in response to the RFS2 mandates. Diesel and jet fuels recover from a slight decline at the outset of the forecast and settle at levels that are at least 50 percent higher by 2030 when compared to 2008 totals.

Table 5.1: Arizona Transportation Fuel Demand

Historical and Forecast (Thousands of Barrels per Day)

	Gasoline		E85		Diesel Fuel		Jet	Totals	
Year	Low	High	Low	High	Low	High	Fuel	Low	High
2006	177.0	177.0	0.0	0.0	58.0	58.0	33.8	268.9	268.9
2007	184.5	184.5	0.0	0.0	57.9	57.9	35.5	277.9	277.9
2008	177.1	177.1	0.0	0.0	60.2	60.2	33.1	270.4	270.4
2010	186.9	187.4	0.0	0.0	59.5	62.1	28.5	274.8	278.0
2020	177.3	210.6	23.3	21.4	74.0	79.2	36.9	311.5	348.1
2030	175.7	233.6	33.5	30.6	90.9	101.6	51.9	351.9	417.6
Incremental Demand Versus 2008 (Thousands of Barrels per Day)									
2010	9.8	10.3	0.0	0.0	-0.7	1.9	-4.6	4.5	7.6
2020	0.2	33.5	23.3	21.4	13.7	19.0	3.9	41.2	77.7
2030	-1.4	56.5	33.5	30.6	30.6	41.4	18.8	81.5	147.2
Percentage Change Compared to 2008									
2010	5.5%	5.8%	NA	NA	-1.2%	3.1%	-13.9%	1.7%	2.8%
2020	0.1%	18.9%	NA	NA	22.8%	31.5%	11.7%	15.2%	28.7%
2030	-0.8%	31.9%	NA	NA	50.8%	68.7%	56.9%	30.1%	54.5%

Source: California Energy Commission analysis

Table 5.2 shows the historical and forecast transportation fuel demand levels for Nevada over the same period. Results are similar for gasoline and the strong increase in renewable fuels.

Table 5.2 Nevada Transportation Fuel Demand

Historical and Forecast (Thousands of Barrels per Day)

	Gasoline		E85		Diesel Fuel		Jet	Totals	
Year	Low	High	Low	High	Low	High	Fuel	Low	High
2006	76.1	76.1	0.0	0.0	49.0	49.0	34.7	159.8	159.8
2007	73.5	73.5	0.0	0.0	47.7	47.7	35.2	156.4	156.4
2008	70.0	70.0	0.0	0.0	47.7	47.7	34.2	151.8	151.8
2010	73.8	74.0	0.0	0.0	47.1	49.1	29.1	150.0	152.3
2020	70.1	83.2	9.2	8.4	58.5	62.7	39.9	177.7	194.2
2030	69.4	92.3	13.2	12.1	71.9	80.4	61.1	215.6	245.8
Incremental Demand Versus 2008 (Thousands of Barrels per Day)									
2010	3.9	4.1	0.0	0.0	-0.6	1.5	-5.1	-1.8	0.5
2020	0.1	13.2	9.2	8.4	10.9	15.0	5.7	25.9	42.4
2030	-0.6	22.3	13.2	12.1	24.2	32.7	26.9	63.8	94.0
Percentage Change Compared to 2008									
2010	5.5%	5.8%	NA	NA	-1.2%	3.1%	-14.9%	-1.2%	0.3%
2020	0.1%	18.9%	NA	NA	22.8%	31.5%	16.8%	17.1%	27.9%
2030	-0.8%	31.9%	NA	NA	50.8%	68.7%	78.5%	42.0%	61.9%

Source: California Energy Commission analysis

Pipeline exports to Arizona and Nevada from California were forecast to determine what range of potential impact there could be for supplies either originating at California refineries or imported through California's marine terminal infrastructure. The Low Export Case from California assumes low fuel demand forecasts in Arizona and Nevada in conjunction with the East Line supplying barrels into Arizona preferentially over barrels being supplied from California through the West Line. Table 5.3 shows the estimated volume of pipeline exports originating from within California. One prominent outcome of this analysis is that the federal RFS2 requirements will essentially negate any demand growth for gasoline over the forecast period. Even so, incremental pipeline exports are still forecast to increase, albeit modestly over the next 20 years.

Table 5.3: Pipeline Exports to Arizona and Nevada from California - Low Case

	Historical and Forecast (Thousands of Barrels per Day)							
	Gasoline		Diesel Fuel		Jet Fuel		Totals	
Year	AZ	NV	AZ	NV	AZ	NV	AZ	NV
2006	63.2	71.7	38.7	49.0	31.2	34.7	133.1	155.4
2007	50.3	70.9	30.0	47.7	32.4	35.2	112.7	153.8
2008	21.8	67.4	25.0	47.7	29.2	34.2	75.9	149.3
2010	21.4	66.4	24.6	47.1	25.2	29.1	71.2	138.7
2020	20.8	64.4	30.7	58.5	32.6	39.9	84.1	155.5
2030	20.8	64.4	37.6	71.9	45.9	61.1	104.2	182.2
	Incremental Exports Versus 2008 (Thousands of Barrels per Day)							
2010	-0.4	-1.0	-0.4	-0.6	-4.0	-5.1	-4.7	-10.6
2020	-1.0	-3.0	5.7	10.9	3.4	5.7	8.1	6.3
2030	-1.0	-3.0	12.6	24.2	16.7	26.9	28.3	32.9
	Percentage Change Compared to 2008							
2010	-1.8%	-1.5%	-1.5%	-1.2%	-13.6%	-14.9%	-6.2%	-7.1%
2020	-4.5%	-4.5%	22.8%	22.8%	11.7%	16.8%	10.7%	4.2%
2030	-4.8%	-4.4%	50.4%	50.8%	57.3%	78.5%	37.2%	22.1%

Source: California Energy Commission analysis

The High Export Case from California assumes high fuel demand forecasts in Arizona and Nevada in conjunction with the East Line supplying barrels into Arizona preferentially over barrels being supplied from California through the West Line. Table 5.4 shows the estimated volume of pipeline exports originating from within California.

Table 5.4: Pipeline Exports to Arizona and Nevada from California – High Case

Historical and Forecast (Thousands of Barrels per Day)

	Gasoline		Diesel Fuel		Jet Fuel		Totals	
Year	AZ	NV	AZ	NV	AZ	NV	AZ	NV
2006	63.2	71.7	38.7	49.0	31.2	34.7	133.1	155.4
2007	50.3	70.9	30.0	47.7	32.4	35.2	112.7	153.8
2008	21.8	67.4	25.0	47.7	29.2	34.2	75.9	149.3
2010	21.5	66.6	25.7	49.1	25.2	29.1	72.3	141.0
2020	34.7	76.1	35.6	62.7	32.6	39.9	102.8	171.4
2030	58.9	84.9	51.9	80.4	45.9	61.1	156.7	211.2

Incremental Exports Versus 2008 (Thousands of Barrels per Day)

2010	-0.3	-0.8	0.7	1.5	-4.0	-5.1	-3.6	-8.3
2020	12.9	8.7	10.6	15.0	3.4	5.7	26.9	22.1
2030	37.1	17.4	26.9	32.7	16.7	26.9	80.7	61.9

Percentage Change Compared to 2008

2010	-1.5%	-1.2%	2.9%	3.1%	-13.6%	-14.9%	-4.7%	-5.6%
2020	59.0%	12.9%	42.5%	31.5%	11.7%	16.8%	35.4%	14.8%
2030	170.1%	25.9%	107.9%	68.7%	57.3%	78.5%	106.3%	41.4%

Source: California Energy Commission analysis

As indicated by the results in the above table, despite the RFS2 increased renewable requirement for gasoline, demand still increases over the forecast period. In part, this is caused by additional pipeline volumes of gasoline and diesel fuel shifting from the East Line to the West Line as pipeline capacity on the East Line is reached as soon as 2015. In fact, by 2030 an additional 41 thousand barrels per day of supplies need to shift to the West Line to avoid exceeding maximum pumping capacity of the East Line system into Tucson and Phoenix.

The continued growth of transportation fuel demand in Arizona and Nevada could eclipse the capacity of some portions of the Kinder Morgan pipeline distribution system during the forecast period, absent additional expansions. Table 5.5 shows the estimated time frames whereby product pipeline capacities would be fully utilized under various scenarios. Most segments are not expected to exceed maximum pumping capacity over the forecast period due to the recent, significant drop in transportation fuel demand and lower demand outlooks linked to increased use of renewable fuels and improved fuel economy standards for motor vehicles.

Table 5.5: Product Pipelines – Maximum Capacity Timing

Pipeline Section From California	2009 Capacity TBD	Year that Maximum Capacity Of Pipeline is Reached	
		Low Case	High Case
Sacramento to Reno	45	Beyond 2030	2025
Colton to Las Vegas	156	2026	2021
Colton to Phoenix	204	Beyond 2030	Beyond 2030
Pipeline Section From Western Texas			
El Paso to Tucson	170	Beyond 2030	Beyond 2030
Tucson to Phoenix	155	Beyond 2030	Beyond 2030

Source: California Energy Commission analysis

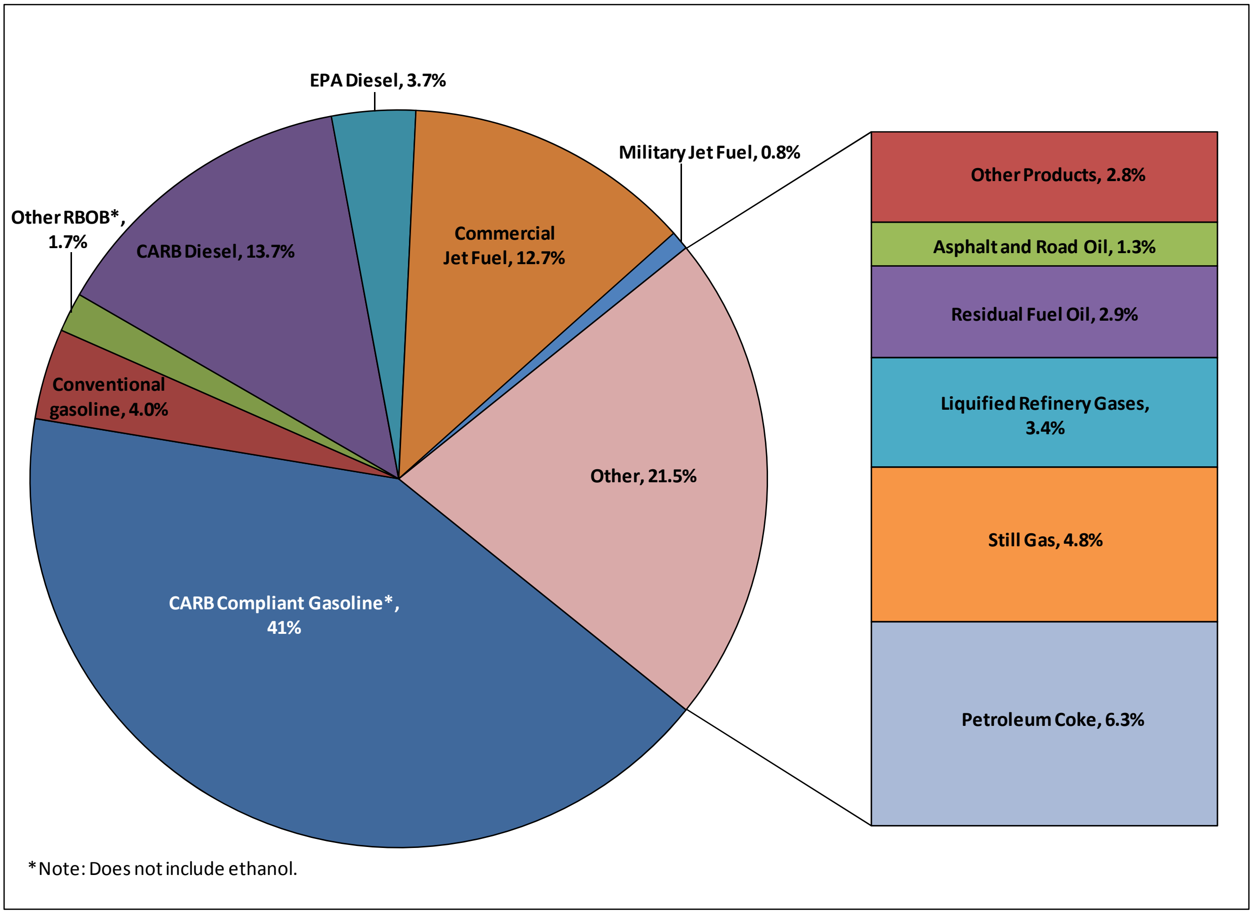
Based on these results of the export analysis, it appears as though there are no pipeline capacity constraint issues that appear imminent. Even if certain pipeline segments get close to capacity, it is assumed that Kinder Morgan will continue to invest capital to expand its distribution infrastructure to accommodate future demand growth.[151] If not, incremental demand for transportation fuels that exceed projected pipeline capacity would have to be supplied via tanker truck or rail car. This mode of transportation fuel delivery is far more expensive compared to pipeline shipments (approximately 2 to 4 times greater). As such, it is likely that additional expansions will continue to occur throughout the forecast period within the Kinder Morgan southwest system or through construction of another petroleum product pipeline system, such as the type of project proposed by Holly Energy Partners that is discussed in greater detail later in this chapter.[152]

Transportation Fuel Import Forecast

The comparison of California's demand forecast with incremental production from refineries located in the state results in the forecast of transportation fuel imports. The incremental demand outlook includes incremental pipeline exports to Arizona and Nevada. The difference between the regional demand growth for transportation fuels and additional refinery output of refined products is a forecast of incremental imports for gasoline, diesel, and jet fuel for 2015, 2020 and 2025.

California refinery production is forecast to continue growing on an incremental basis for the Low Import Case scenario only. This refinery creep of crude oil distillation capacity will yield additional refinery blendstocks that will be converted to transportation fuels for use in California and for export to neighboring states and other locations. Staff assumed that the proportion of transportation fuels produced by processing additional quantities of crude oil will be similar to the ratios that were observed during 2008. Figure 5.3 depicts the percentage of various transportation fuel types that were produced in 2008 for each barrel of crude oil processed.

Figure 5.3: California Refinery Output in 2008 by Product Type



Source: PIIRA data and California Energy Commission analysis

Applying this ratio of transportation fuel output to the incremental crude oil that is processed, the supply of gasoline, diesel, and jet fuel produced from California refineries increased by a range of 69,000 to over 135,000 barrels per day. Table 5.6 lays out the incremental production by each type of transportation fuel over the forecast period, assuming refiners continue to gradually process ever larger quantities of crude oil each year under the Low Import Case scenario.

Table 5.6: California Incremental Refinery Production

(Thousands of Barrels per Day)

	Low Import Case			High Import Case		
Transportation Fuel	2015	2020	2025	2015	2020	2025
California Gasoline	36.4	55.7	71.5	0.0	0.0	0.0
Export Gasoline	5.0	7.6	9.8	0.0	0.0	0.0
California Diesel Fuel	12.6	19.3	24.8	0.0	0.0	0.0
EPA Diesel Fuel	3.4	5.2	6.6	0.0	0.0	0.0
Jet Fuel	11.6	17.8	22.8	0.0	0.0	0.0
Totals	69.0	105.6	135.4	0.0	0.0	0.0

Source: California Energy Commission analysis

Under the High Import Case analysis (see Table 5.7), California net imports of gasoline are forecast to decrease significantly over the next 15 years, while imports of diesel and jet fuel would need to rise to keep pace with growing demand for those products. Under the Low Import Case scenario, the growing imbalances between gasoline and the other transportation fuels are even more extreme, resulting in a net decline of imports of at least a quarter million barrels per day by 2015.

Table 5.7: California Incremental Imports of Transportation Fuels

Net Change (Thousands of Barrels per Day)

		Low Import Case			High Import Case		
Transportation Fuel	2008	2015	2020	2025	2015	2020	2025
Gasoline	51.3	-191.8	-328.0	-386.6	43.3	-19.3	-66.2
Diesel Fuel	-65.9	-71.0	-59.1	-42.4	-33.6	-8.0	20.0
Jet Fuel	-6.9	11.5	45.6	88.3	29.1	77.7	136.8
Totals	-21.6	-251.3	-341.5	-340.6	38.9	50.5	90.6

Reduced Imports of Gasoline Blendstocks

		Low Import Case			High Import Case		
Transportation Fuel	2008	2015	2020	2025	2015	2020	2025
Gasoline	51.3	***-138.0***	***-274.2***	***-332.8***	43.3	***0.0***	***-12.4***
Diesel Fuel	-65.9	-71.0	-59.1	-42.4	-33.6	-8.0	20.0
Jet Fuel	-6.9	11.5	45.6	88.3	29.1	77.7	136.8
Totals	-21.6	-197.5	-287.7	-286.8	38.9	69.7	144.4
Gasoline Blendstocks	53.8	0.0	0.0	0.0	53.8	34.5	0.0

Reduced Receipts of Unfinished Refinery Feedstocks

		Low Import Case			High Import Case		
Transportation Fuel	2008	2015	2020	2025	2015	2020	2025
Gasoline	51.3	***0.0***	***-120.4***	***-178.9***	43.3	***0.0***	***0.0***
Diesel Fuel	-65.9	***-62.4***	***-49.5***	***-32.7***	-33.6	-8.0	**20.7**
Jet Fuel	-6.9	11.5	45.6	88.3	29.1	77.7	136.8
Totals	-21.6	-50.8	-124.3	-123.4	38.9	69.7	157.6
Gasoline Blendstocks	53.8	0.0	0.0	0.0	53.8	34.5	0.0
Refinery Feedstocks	192.3	19.8	0.0	0.0	192.3	192.3	176.8

Source: California Energy Commission analysis

It is recognized that this type of initial outcome is unlikely to materialize as refiners will adjust operations to decrease the ratio of gasoline components that are produced for each barrel of crude oil processed. One such example is for refiners to eliminate the imports of gasoline blending components so that production is lower, thus reducing the imbalance for gasoline over the forecast period. Another example of refinery operational changes is to reduce the quantity of unfinished gas oils used as a feedstock for certain refinery process equipment. This approach can further reduce the gasoline imbalance over the next couple of decades. It should be noted that these two examples of refinery operational changes would not alter the quantity of crude oil being processed at the refineries. As such, refiners may also need to reduce the quantity of crude oil processed at the refineries by lowering the utilization rates or closing some portion of the state's refining capacity. The potential trend of declining gasoline demand in conjunction with rising diesel fuel demand is something that the European refining market has evolved to over several years. That situation has resulted in large excess supplies of gasoline that require export outside of Europe and a growing shortfall of local refinery distillate production that must be imported from outside the region.

Marine Vessels–Incremental Voyages

The increased imports (or exports as the case may be) of transportation fuels is expected to result in a greater number of marine vessels (referred to as product tankers) utilizing California marine terminals. Staff has examined recent import information to determine an average cargo size per product tanker import or export event. Petroleum tankers are constructed with multiple compartments that enable the transport of more than one type of petroleum product per voyage. In addition, some product tankers will discharge or load cargoes at more than one marine terminal. Finally, staff recognizes that there are instances where transportation fuels are imported or exported via ocean-going barges that have smaller cargo capacities when compared to typical product tankers.

For purposes of calculating additional product tanker trips, staff used an upper limit of 300,000 barrels of cargo capacity per import or export event and a lower limit of 150,000 barrels capacity. The upper limit is an average of the largest product tankers (top 25 percent) that were involved in a foreign import of transportation fuels in 2008. The lower range was estimated by using the average size of all of the foreign product tanker vessels for 2008. It is assumed that the bulk of the incremental imports or exports of transportation fuels will either originate from foreign sources (for imports) or be transported to foreign destinations (for exports). Using these two estimates for product tanker capacity, staff calculated the incremental number of import and export events that could be required over the forecast period (see Table 5.8).

Table 5.8: California Incremental Product Tanker Visits

	Low Import Case			High Import Case		
Marine Vessel Size	2015	2020	2025	2015	2020	2025
150,000 Barrels	-611	-831	-829	95	123	220
300,000 Barrels	-306	-416	-414	47	61	110

Source: California Energy Commission analysis

The negative numbers in the above table are actually incremental export events that could occur if a large imbalance develops between growing California refining production and shrinking gasoline demand created by the RFS2 mandates. As stated earlier, this scenario is unlikely to develop absent changes in operation of the existing refineries.

Additional Factors with Potential for Impact

A number of near-term factors could increase the uncertainty of the transportation fuels import forecast, namely: new expansion projects for California refineries; level or reduced capacity for processing crude oil; and construction of a new petroleum product pipeline to one of the neighboring states from a supply source located outside of California.

California Refinery Expansion

There are no refinery expansion projects examined as alternative scenarios during this IEPR cycle. Although two refinery projects have been closely monitored by staff over the last year, neither of these proposed refinery production expansions are deemed likely over the near-term and have been excluded from alternative scenario assessment.

The Chevron Energy and Hydrogen Renewal Project at its Richmond refinery initially involved the replacement of two catalytic reformer reactors with a single Continuous Catalyst Regeneration (CCR) refinery process unit.[153] This portion of the project would have increased the production of gasoline by approximately 300,000 gallons per day or about 7.14 thousand TBD.[154] However, Chevron has recently decided that the CCR portion of the project "will be indefinitely delayed due to a combination of factors, including weakened demand for product and higher construction costs and a tough economic environment following a rather lengthy permitting process."[155]

The other proposed refinery project being monitored by staff is the production capacity expansion for gasoline and diesel fuel associated with the Big West refinery in Bakersfield. The Clean Fuels Project (CFP) is designed to convert partially processed crude oil (gas oils), that is normally exported from the refinery, into approximately 1.3 million gallons per day of transportation fuels (about 20,000 barrels per day of diesel fuel and up to 10,000 barrels per day of gasoline).[156] However, the parent company for Big West of California, Flying J, filed for Chapter 11 protection during December 22, 2008.[157] At the time of this writing, the Bakersfield refinery is idled. Staff assumes that the refinery will resume operations at normal rates by January of 2011, at the latest. Due to the inactive status of the facility and the uncertainty associated with significant funding for the proposed refinery expansion work, this additional quantity of refined product output associated with the CFP was not included as part of any alternative scenarios.

No Growth of California Refinery Distillation Capacity

Over time, the capacity of California refineries to process crude oil has gradually increased. Staff has assumed that this continual refinery creep will continue as part of the base assumptions used in the primary analysis of imports and exports of refined transportation fuels. However, if the assumption is changed to one whereby the distillation capacity of the California refineries remains fixed over the forecast period, the quantity of imported transportation fuels will be greater and the amount of crude oil imported will be lower than the information presented under the Low and High demand scenarios. Table 5.9 shows that the exports of transportation fuels could be over 100 TBD less by 2020 under the Low Import Case and imports of transportation fuels over 175 TBD higher under the High Import Case scenario.

New Petroleum Product Pipeline Project

As described earlier in this chapter, California is an important source of transportation fuels for Nevada and Arizona. These fuels are primarily delivered to these neighboring states via petroleum product pipelines operated by Kinder Morgan. Periodically, proposed pipeline projects are announced that are designed to provide new sources of supply to these adjacent states from supply regions outside of California. If such a pipeline project were to be constructed, these additional supplies would compete with existing sources and could diminish the forecasted demand for petroleum product pipeline exports to Nevada and/or Arizona.

Holly Energy Partners and Sinclair Oil have partnered in a planned project to construct the 406-mile UNEV petroleum product pipeline that originates in Utah and terminates in northern Las Vegas. The purpose of the pipeline is to provide transportation fuels to the Las Vegas market from refineries located in the Salt Lake City area. Construction on the terminal in Cedar City, Utah has already commenced and the pipeline work is scheduled to begin later in the summer of 2009. The pipeline could become operational as early as the fall of 2010 with an initial pumping capacity of 62,000 BPD. Over time, the pipeline system could be expanded to a maximum pumping capacity of up to 118,000 BPD. [158]

An alternative scenario examined for this chapter involves the potential impact on the pipeline export forecast into southern Nevada that could occur as a result of the UNEV pipeline project being built and delivering transportation fuels into Las Vegas. The 62,000 BPD UNEV capacity was examined in conjunction with both the High and Low Demand Cases for Nevada to quantity the potential impact on California pipeline exports to southern Nevada. However, it is unclear at this point what quantity of spare refinery production capacity in the Utah region may be available to provide excess supply to the UNEV pipeline. It is possible that the pipeline will not initially operate at full capacity when construction is completed.

Results of this scenario are presented in Table 5.9. Under the Low Import Case, pipeline exports to Las Vegas from points originating in California could be reduced by up to 62 TBD by 2015. This scenario could displace approximately 50 percent of the forecasted pipeline deliveries to Las Vegas from California by this time. Under the High Import Case, operation of the UNEV pipeline could displace up to 83 percent of the forecasted California-sourced deliveries by 2020, assuming the new pipeline operates at the higher capacity of 118 TBD by that time. The UNEV pipeline project has the potential to reduce export demand on California refineries and marine import infrastructure, as well as improve supply redundancy options for the Las Vegas markets during periods of temporary interruption of petroleum product pipeline operations.

California Renewable Fuel Demand, Production, and Imports

California ethanol demand is forecast to increase primarily from federal and state mandates that are discussed at length in Chapter 3 of this report. It is unclear the exact nature of the infrastructure necessary to handle the increased quantity of ethanol anticipated over the near and mid-term period. The LCFS is likely to greatly complicate planning for the necessary logistics and supply modifications.

Summary of Transportation Fuel Import Forecast

The following Table 5.9 contains the incremental import forecast of transportation fuels for the Low and High Cases in 2015, 2020 and 2025. The table also displays the summary of the impacts on incremental imports (or exports for negative numbers) that could be assumed based on the additional factors examined regarding refinery operations and new pipeline projects.

Table 5.9: Summary of Import Forecast & Additional Factors

Incremental Imports of Transportation Fuels (Thousands of BPD)

	Low Case			High Case		
	2015	2020	2025	2015	2020	2025
Transportation Fuels Forecast Results	-251.3	-341.5	-340.6	38.9	50.5	90.6
Refinery Projects and Operations						
New UNEV Pipeline (CalNev Line Only)	-313.3	-403.5	-458.6	-23.1	-11.5	-27.4
No California Refinery Creep	-182.3	-235.9	-205.2	38.9	50.5	90.6

Source: California Energy Commission analysis

APPENDIX A

TRANSPORTATION FUEL DEMAND FORECASTING METHODS

The transportation fuel demand forecasting methods closely follow those described in the *2007 IEPR*. However, various inputs and assumptions to the models have been updated. In some cases, the models have been changed or updated, but the forecasting methods have remained consistent with previous forecasts.

Light Duty Vehicle Fuel Demand Model

The current model was patterned after the Energy Commission's Personal Vehicle Demand Model developed in 1983. The CALCARS model was designed to evaluate impacts of public policy on overall light-duty vehicle fuel use, facilitate the development of strategies to reduce California's dependence on petroleum, and help promote alternative fuels and alternative fuel vehicles.

CALCARS is a discrete vehicle choice model that is used to forecast California light-duty vehicle ownership, VMT, and light-duty vehicle fuel demand by simulating vehicle purchase decisions and fuel use by California motorists. These forecasts are based on projections of California demographic and economic trends, fuel prices, vehicle attributes, and current consumer preferences for light-duty vehicles.

Over the past two decades, the CALCARS model has been updated with new information several times, in 1996 and for the *2003*, *2005*, *2007* and current *IEPRs*. The detailed information integrates demographic and economic data with preference data to evaluate consumer vehicle choices. The 2009 updates include:

- Consumer preferences from an Energy Commission 2008 California vehicle survey.
- Forecasts of transportation fuel prices in California.
- 2007 DMV registered on-road vehicles counts.
- Forecasts of light-duty vehicle fuel economy and attributes.
- New fuel and vehicle types.
- Forecasts of light-duty vehicle fuel economy and attributes.
- Forecasts of California demographic data.
- Forecasts of California economic growth.

As a discrete choice model, CALCARS requires the collection of data on consumer preferences from a representative sample of Californians and vehicle characteristics, such as operating cost and vehicle price. The 2008 California Vehicle Survey collected stated preference data from 3274 residential households and 1780 commercial vehicle owners in California and used this data to estimate and update the CALCARS model. A total of 105 classes of vehicles and 17 model years were incorporated into the model using the 2008 California Vehicle Survey.

California Freight Energy Demand (Freight) Model

The Freight model was developed in 1983 to forecast demand for truck and rail freight transportation fuels. The Freight model projects volumes of freight transported by truck and rail, truck stock, and VMT, along with truck and rail consumption of gasoline, diesel, and LPG for five California regions. These outputs are driven by projections of economic activity in 16 economic sectors and fuel cost projections. The Freight model analyzes rail and truck mode choices, as well as truck type choices, and produces detailed projections of activity and fuel consumption within California for all trucks and rail-freight operations. The model also analyzes public policy by measuring the impact of fuel prices and other costs on vehicle choice, fuel choice, mode choice, and fuel economy.

The model was updated in 1998, but reflects energy markets and regulatory environments that have changed substantially since the early 1980s. The 1998 improvements include a new modal diversion model, as well as adding new data on freight operation cost and fuel efficiency and updating other data average truck payloads, rail carloads, and truck survival rates.

California Transit Energy Demand (Transit) Model

The Transit is a discrete choice travel demand model that was developed in 1983 to produce long-term forecasts of travel demand and energy consumption by urban bus and rail transit systems, intercity bus and rail, school buses, and other buses operating in California. The model estimates the effects of changes in transit fares, service policies, automobile fuel economy, gasoline prices, population, employment, and income on transit energy consumption. As a travel demand model, it is also capable of estimating the effectiveness of policies designed to save energy by promoting trip diversions from automobile to transit mode.

The original model included 16 transit agencies in California, mostly from the Bay Area and Southern California. As part of the ongoing effort to update input data and collect current information about transit agencies, the staff has surveyed additional transit agencies to expand the data set and generate forecasts for 64 transit agencies and incorporate expanded service areas and transit fuel types. Population, income, fuel prices, and other data have been updated to accommodate the 2006-2007 fiscal year, the last year with complete data, as the base year for forecasting.

California Civil Aviation Jet Fuel Demand (Aviation) Model

The commercial aviation demand for jet fuel is derived from demand for passenger air travel and air freight transportation. Staff separated these sectors by identifying airlines that only transport freight from airlines whose primary activity is transporting passengers, but some of which transport freight as well. While this will leave some freight in the passenger aviation model, these airlines are still primarily driven by passenger demand. Passenger aviation fuel demand model uses income, employment, aviation fuel prices and passenger plane specific fuel economy projections to forecast passenger miles and jet fuel demand for passenger air transportation. Freight aviation fuel demand model uses freight cargo-specific fuel economy and the economic projections to forecast freight ton miles and jet fuel demand for air freight. Staff derived two fuel economy projections from FAA data. One fuel economy scenario was based on the assumption that the aviation industry will meet the FAA's goal of improving fuel economy by 1 percent for every forecast year. The second fuel economy scenario was based on the fuel economy improvements imputed from FAA forecasts and holding it constant between 2025 and 2030. These alternative fuel economy scenarios were combined with two price scenarios to form four aviation fuel demand cases.

Other Transportation Fuel Sectors

Off-road diesel is defined in this report as diesel used in California that is for non-highway use. Some off-road uses of diesel are for transportation, such as agriculture, construction, ocean-going vessels, and inland watercrafts. Other off-road uses of diesel include portable electric generation, heating, and the like. Historical information regarding this component of diesel demand indicates that agriculture and construction sectors are the largest users of off-road diesel. The *2009 IEPR* will continue the use of the *2007 IEPR* growth rate assumptions. Further work in modeling this sector is expected to occur for the *2011 IEPR*.

Although some diesel is used in marine applications, ocean going vessels primarily use residual fuel oil, for which staff has produced no demand forecast in this report.

Land Use and Personal Vehicle Miles Traveled Demand

Increasing attention to the relation between land use and transportation demand has prompted the growing efforts in land use and transportation model integration. The models staff has used to forecast fuel demand did not include a land use model, but indicators of land use are incorporated in the model. Residential VMT is estimated with a single equation, which complements the residential vehicle choice model. This residential VMT equation accounts for the significant impact of miles-to-work on the miles traveled. Additionally, as a standard travel demand model, the transit model incorporates travel time, which accounts for some travel related-land use characteristics.

APPENDIX B

CALIFORNIA TRANSPORTATION FUEL PRICE FORECASTS

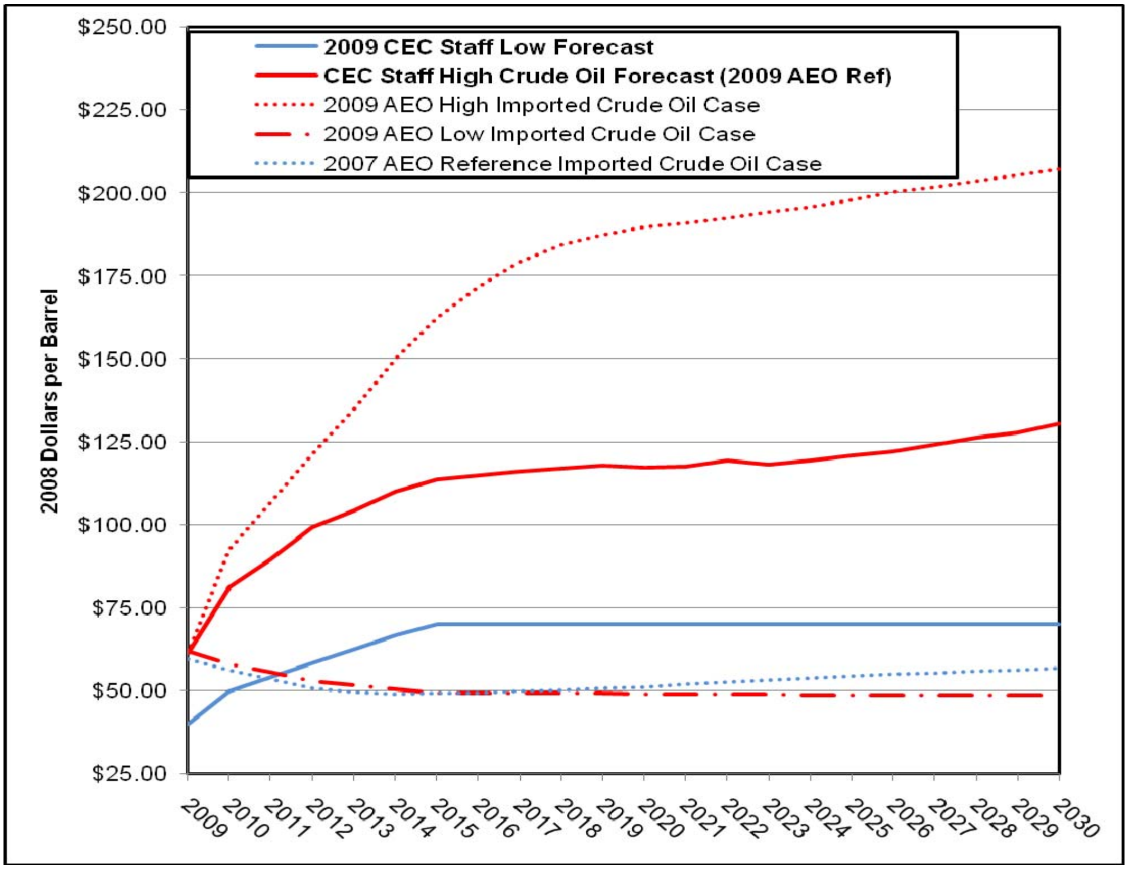
Summary

Staff has developed High and Low Crude Oil Price Case forecasts for California transportation fuels based on the U.S. EIA *2009 Annual Energy Outlook* Reference Case and Energy Commission Low Case oil price forecasts, respectively. The Energy Commission's High Case starts at $2.90 per gallon for gasoline and $3.09 for diesel in 2009, jumps to $4.36 and $4.43, respectively, in 2015, and then continues to rise to $4.80 and $4.87 by 2030 (all prices are in 2008 dollars, to adjust for inflation).[159] Energy Commission Low Case price forecasts start at $2.34 for gasoline and $2.42 for diesel per gallon in 2009, climb to $3.17 and $3.19, respectively, in 2015, and then hold constant until 2030. Staff has also prepared price forecasts for other transportation fuels, including railroad diesel, jet fuel, E-85, biodiesel, electricity, compressed natural gas, liquefied natural gas, propane, and hydrogen, that are discussed later in this appendix.

Crude Oil Price Forecast Assumptions

Staff has based California-specific High and Low Case regular-grade gasoline and diesel price forecasts on crude oil price forecasts. The United States refiner acquisition cost (RAC) of imported crude oil, as defined and measured by U.S. EIA, is used as a proxy for crude oil prices. This index is the average price of all imported crude oil and is roughly $5–7 per barrel less than the index for higher-quality imported light sweet oil.[160] The High Crude Oil Price Case forecast is based on the U.S. EIA *2009 AEO* Reference Case. The Low Crude Oil Price Case forecast is an Energy Commission staff estimate approximating alternative crude oil price forecasts from other organizations identified by the *2009 AEO*. Figure B-1 compares the 2009 Energy Commission staff and various U.S. EIA crude oil price forecasts.[161]

Figure B.1: Comparison of Energy Commission 2009 Staff Crude Oil Price Forecasts With EIA *2007* and *2009 AEO* Forecasts (in 2008 dollars)



Source: U.S. Energy Information Administration – *Annual Energy Outlook* (*AEO*) and California Energy Commission

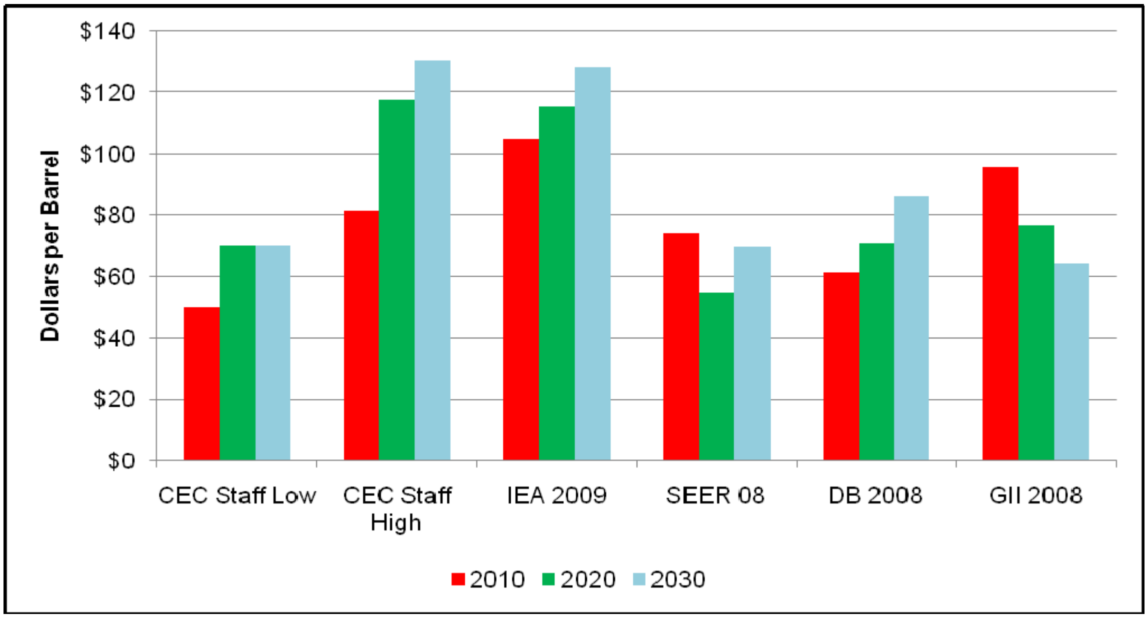
Table B.1 shows the Energy Commission crude oil price forecast cases, and Figure B.2 compares the Energy Commission low and high crude oil price forecasts with crude oil price forecasts by other well-known forecasters in the field.

Table B.1: Energy Commission 2009 Staff Crude Oil Price Forecast Cases (real and nominal dollars per barrel)

	Energy Commission Staff High Crude Oil Price Case [AEO 2009 Reference Case]		Energy Commission Staff Low Crude Oil Price Case	
Year	2008$	Nominal	2008$	Nominal
2009	$61.49	$61.94	$40.09	$40.38
2010	$81.37	$82.09	$49.96	$50.40
2011	$89.77	$91.83	$54.14	$55.38
2012	$99.49	$103.56	$58.31	$60.69
2013	$104.64	$110.85	$62.48	$66.19
2014	$110.11	$118.45	$66.65	$71.71
2015	$113.85	$124.48	$70.00	$76.53
2016	$115.15	$128.03	$70.00	$77.83
2017	$116.16	$131.33	$70.00	$79.14
2018	$117.05	$134.56	$70.00	$80.47
2019	$118.02	$137.94	$70.00	$81.81
2020	$117.54	$139.65	$70.00	$83.17
2021	$117.83	$142.32	$70.00	$84.55
2022	$119.69	$146.96	$70.00	$85.95
2023	$118.50	$147.88	$70.00	$87.36
2024	$119.62	$151.74	$70.00	$88.79
2025	$120.98	$155.92	$70.00	$90.22
2026	$122.20	$160.00	$70.00	$91.65
2027	$124.47	$165.53	$70.00	$93.09
2028	$126.62	$171.00	$70.00	$94.54
2029	$127.95	$175.47	$70.00	$96.00
2030	$130.71	$181.98	$70.00	$97.46

Sources: U.S. Energy Information Administration and the California Energy Commission

Figure B.2: Energy Commission and Other Crude Oil Price Forecasts (in 2008 dollars)



Sources: U.S. Energy Information Administration and the California Energy Commission

* Energy Commission staff crude oil high price case is the same as the 2009 AEO reference price case.

** GII = Global Insight, IEA = International Energy Agency, DB = Deutsche Bank, SEER = Strategic Energy and Economic Research

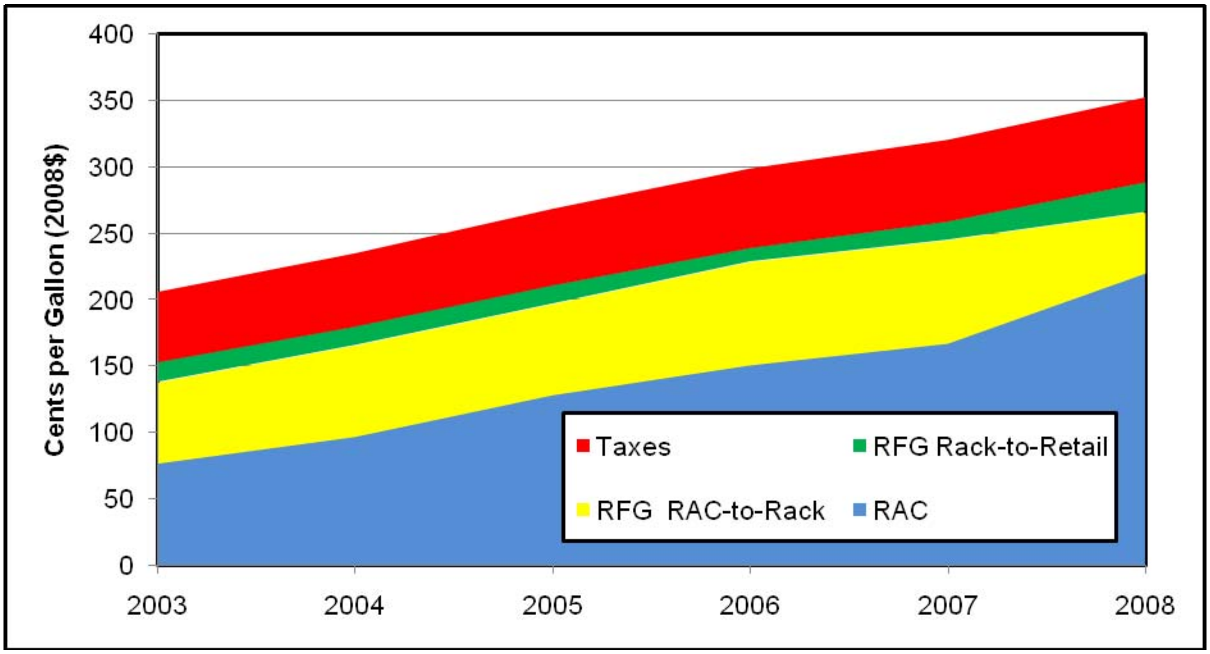
Petroleum Transportation Fuel Price Forecast Assumptions

Staff established relationships between wholesale fuel and crude oil prices using monthly crude oil price data from the EIA and average monthly California rack prices for gasoline and diesel from the Oil Price Information Service (OPIS). The January 2003 to December 2008 period was used in deriving the price margins because during this time MTBE-free reformulated gasoline was the dominant gasoline refined and used in the state.

The difference between monthly RAC crude oil price and the OPIS California average monthly gasoline and diesel rack prices is referred to as the "crude oil to rack price" margin. This margin varies over time on a monthly basis, and the decision to use one period's historical margin over another's can make a difference in the final retail fuel price forecast.

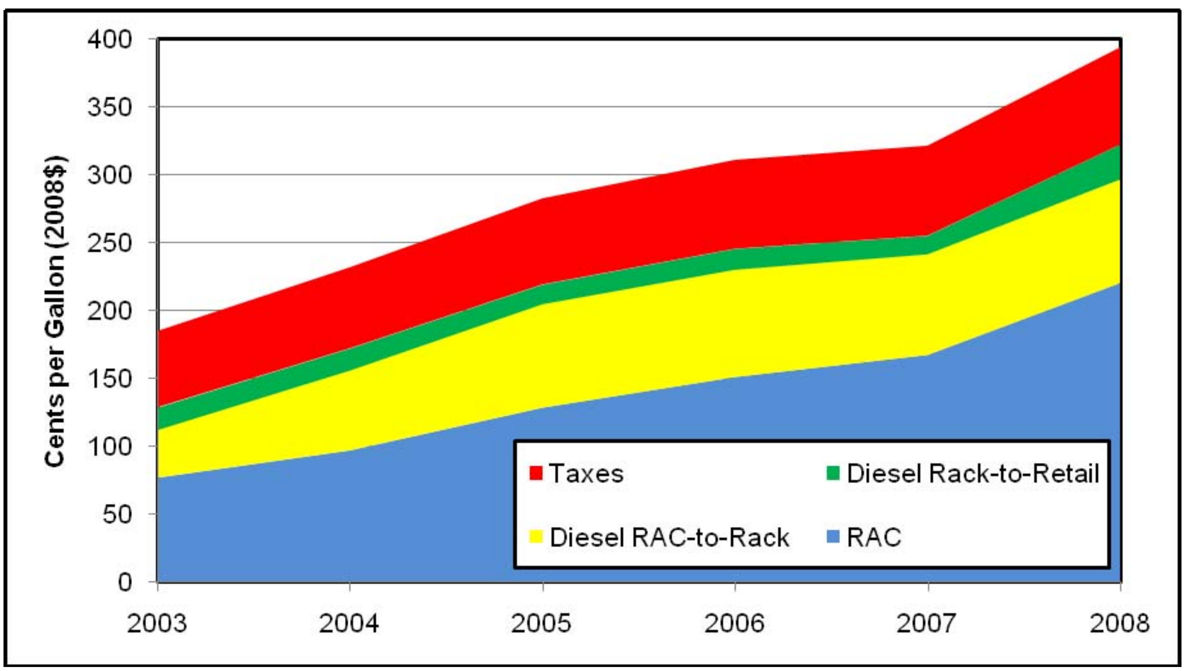
The next step was to determine the "rack to retail price" margin, as the historical differences between the weekly OPIS rack price and the weekly U.S. EIA retail price series (excluding taxes) for both California regular-grade gasoline and diesel. Again, the decision to choose one period's margin as representative of future expectations will affect the final retail price forecast. Figures B.3 and B.4 illustrate the components of the retail prices paid by the consumers at the pump for gasoline and diesel, including RAC crude oil prices, annual averages of both "crude oil to rack price" and "rack to retail price" margins, and taxes.

Figure B.3: California Retail Gas Price Components 2003 – 2008 (in 2008 Dollars)



Source: California Energy Commission

Figure B.4: California Retail Diesel Price Components 2003 – 2008 (in 2008 Dollars)



Source: California Energy Commission

Table B.2 summarizes the crude oil to rack price margins and the rack to retail ex-tax margins that are used with the two crude oil price cases, in forecasting gasoline and diesel prices. All prices are in 2008 CPG, and they represent annual averages of the monthly prices, in all cases. The High Price Case margins (for both gasoline and diesel) were based on years of higher combined margins (2006–2008 data) and the Low Price Case margins, on lower levels (2003–08 data).

Table B.2: Margins Used in RFG and Diesel Price Forecast Cases (2008 cents per gallon)

Energy Commission Crude Price Case	Crude-to-Rack		Rack-to-Retail	
	RFG	Diesel	RFG	Diesel
Energy Commission High Price	67.2	76.7	15.5	18.1
Energy Commission Low Price	66.7	66.9	14.9	16.9

Source: California Energy Commission

In 2007, ARB adopted regulation to require 10 percent ethanol content in gasoline formulation, which Energy Commission staff expects to raise the price of gasoline. Adders were estimated for the gasoline price forecast to reflect these changes. In the Low Case 5 cents per gallon were added and in the High Case 10 cents per gallon were added starting in 2012. For the early adoption years of 2010 and 2011, these values were 2.5 cents per gallon in the Low Case and 5 cents per gallon in the High Case.

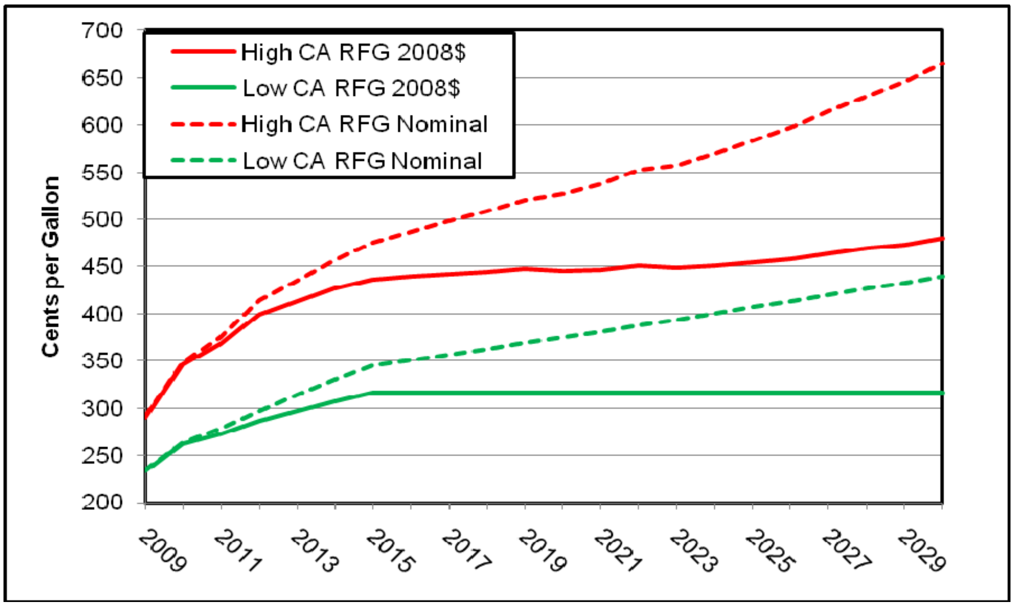
The last step in generating a final retail price forecast for each of the fuels is to add excise and sales taxes and fees. In the case of regular-grade gasoline, combined federal and state excise taxes (including fuel use and underground storage tank levies) totaled $0.378, and sales tax was estimated at 8 percent. For diesel, the federal excise taxes add up to $0.244, and the state excise taxes add up to $0.194. In the case of diesel, however, $0.18 of the state excise tax was included after sales tax was calculated over the remainder of the costs, as that portion is exempt from sales taxation.

Using the previously described diesel fuel crude-to-rack price margins and crude oil price forecasts, staff developed railroad diesel and jet fuel High and Low Price Case forecasts for the 2009-2030 period. Excise tax of $0.069 per gallon and California sales tax of 8 percent are added to the wholesale diesel fuel price to generate the final railroad diesel price forecast estimates. California sales tax of 8 percent does not apply to certified commercial air carriers and therefore is excluded from the final jet fuel price forecasts. However, a $0.044 per gallon excise tax and a distribution adder equal to half the corresponding diesel rack-to-retail margin are added to the wholesale diesel fuel price to generate the final jet fuel price forecast.

California Petroleum Fuel Price Forecasts

Figure B.5 illustrates the annual average gasoline price projections in both real and nominal 2008 dollars using the assumptions described above. Nominal prices represent the average prices customers would actually see at the pump during that year.

Figure B.5: California Gasoline Price Forecasts (real and nominal cents per gallon)



Source: California Energy Commission

Table B.3 shows the annual average retail fuel price projections for regular-grade California gasoline, California diesel, California railroad diesel, and California jet fuel in 2008 dollars using the assumptions outlined above.

Table B.3: California Retail Petroleum Transportation Fuel Price Forecasts (2008 cents per gallon)

	High Crude Oil Price Forecast				Low Crude Oil Price Forecast			
	RFG	Diesel	Railroad Diesel	Jet Fuel	RFG	Diesel	Railroad Diesel	Jet Fuel
2009	290	309	249	237	234	242	183	176
2010	347	360	300	284	262	267	209	200
2011	369	381	322	304	273	278	219	209
2012	399	406	347	327	287	289	230	219
2013	413	420	360	340	297	299	241	229
2014	427	434	374	353	308	310	251	239
2015	436	443	383	361	317	319	260	247
2016	440	447	387	365	317	319	260	247
2017	442	449	389	367	317	319	260	247
2018	444	452	392	369	317	319	260	247
2019	447	454	394	371	317	319	260	247
2020	446	453	393	370	317	319	260	247
2021	446	454	394	371	317	319	260	247
2022	451	458	398	375	317	319	260	247
2023	448	455	395	373	317	319	260	247
2024	451	458	398	375	317	319	260	247
2025	455	462	402	378	317	319	260	247
2026	458	465	405	381	317	319	260	247
2027	464	471	411	387	317	319	260	247
2028	469	476	416	392	317	319	260	247
2029	472	480	420	395	317	319	260	247
2030	480	487	427	402	317	319	260	247

Source: California Energy Commission

Alternative Transportation Fuel Price Forecasts

For the *2009 IEPR* cycle, staff has expanded the list of transportation fuel price forecasts to include the following: E85, B20, transportation electricity rates, CNG, LNG, hydrogen, and propane. These price forecasts are inputs to the vehicle manufacturer offerings forecasts and fuel demand forecasts. It should be noted that the formulation and implementation of current and potential future policies add to the uncertainty in forecasting the prices for these alternative transportation fuels. High and low price forecasts were developed after consultation with the other offices within the Energy Commission regarding all of these fuel types.

Propane and Renewable Fuel

High and low price projections for E85, B20, and propane for transportation use, are based on the corresponding high and low RAC price forecasts used by gasoline and diesel fuels. The E85 price bands are based on E85 being priced on a gasoline gallon equivalency, thus making it the same price as gasoline on an energy content basis.

In the case of biodiesel, analysis of B20 wholesale prices yields an average 52.9 cent difference between diesel rack and B20 rack prices in 2008. Due to the limited amount of information regarding B20 prices under different market conditions, the same 52.9 cent margin was applied at the rack level to both high and low B20 forecasts. High and Low diesel rack-to-retail margins were then applied along with taxes to obtain the final price forecast.

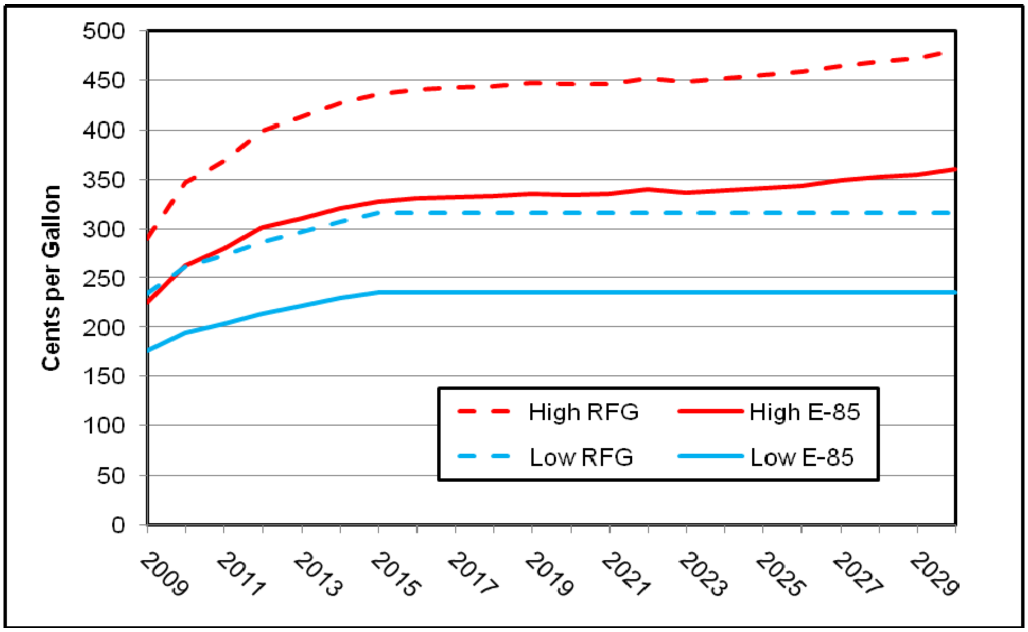
Transportation propane prices were projected based on an assumed wholesale propane price link with RAC. From 2000 to 2008, the wholesale propane prices averaged to 91 percent of RAC. This ratio was applied to the high crude oil price forecast to develop the high wholesale propane price forecast. Staff used a similar method to develop the low price forecast but based this on the 2007-2008 average propane wholesale to RAC price ratio of 76 percent. This ratio was applied to low crude oil price forecast to obtain the low wholesale propane price forecast.
U.S. EIA data on wholesale to retail price margins was used to estimate the high price margin of 64 cents based on the 2000-2004 data and low price margins of 55 cents based on the 1994-2004 data. Table B.4 and Figures B.6, B.7, and B.8 display E85, B20, and propane retail price forecasts for 2009 to 2030.

Table B.4: California Petroleum-Related
Alternative Transportation Fuel Retail Price Forecasts
(2008 cents per gallon)

	High Crude Oil Price Forecast				Low Crude Oil Price Forecast			
Year	RFG	E85	Propane	Bio-Diesel	RFG	E85	Propane	Bio-Diesel
2009	290	225	244	354	234	176	168	299
2010	347	263	291	402	262	195	187	324
2011	369	280	310	425	273	204	196	335
2012	399	301	333	450	287	214	204	346
2013	413	311	345	462	297	222	212	356
2014	427	321	358	489	308	230	220	367
2015	436	328	367	498	317	236	227	376
2016	440	331	370	501	317	236	227	376
2017	442	333	372	501	317	236	227	376
2018	444	334	374	506	317	236	227	376
2019	447	336	376	506	317	236	227	376
2020	446	335	375	505	317	236	227	376
2021	446	336	376	507	317	236	227	376
2022	451	340	380	513	317	236	227	376
2023	448	337	378	513	317	236	227	376
2024	451	339	380	516	317	236	227	376
2025	455	342	383	518	317	236	227	376
2026	458	344	386	521	317	236	227	376
2027	464	349	392	528	317	236	227	376
2028	469	353	397	532	317	236	227	376
2029	472	355	400	537	317	236	227	376
2030	480	361	406	542	317	236	227	376

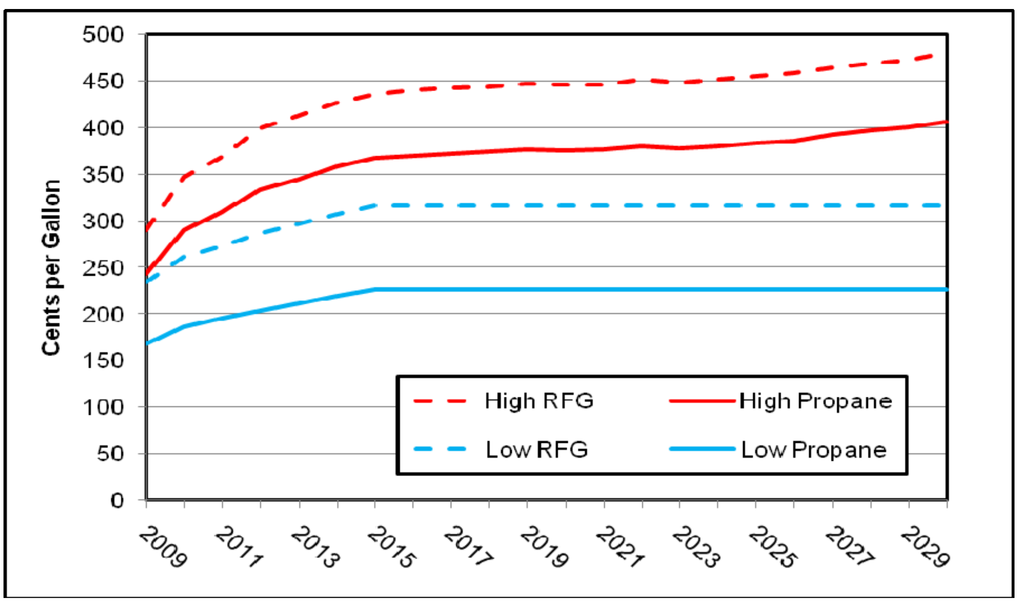
Source: California Energy Commission

Figure B.6: California RFG and E-85 Fuel Price Forecasts (2008 cents per gallon)



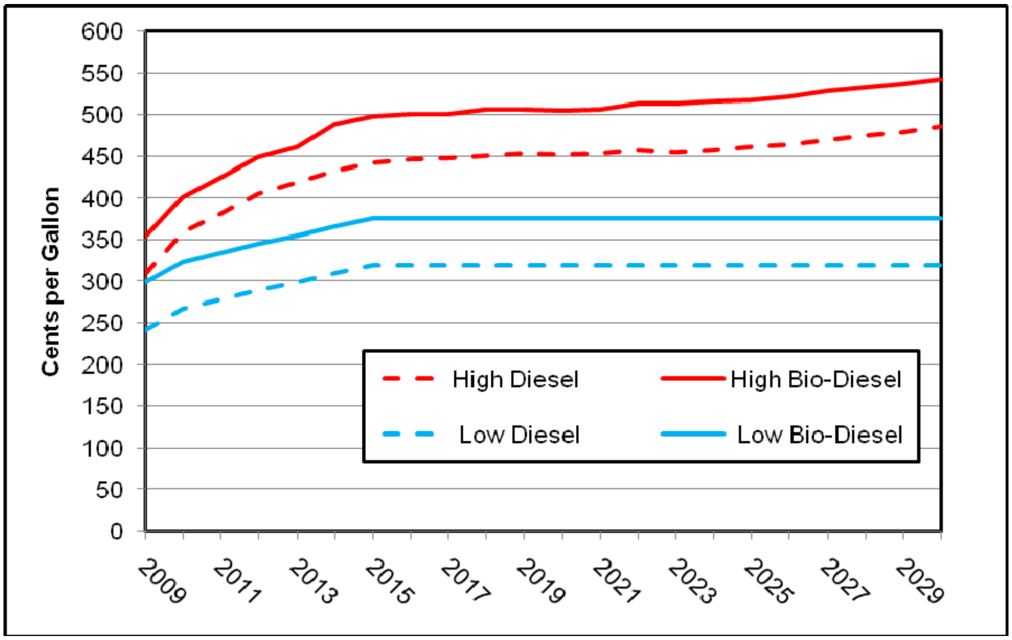
Source: California Energy Commission

Figure B.7: California RFG and Propane Fuel Price Forecasts (2008 cents per gallon)



Source: California Energy Commission

Figure B.8: California Diesel and Biodiesel Fuel Price Forecasts (2008 cents per gallon)



Source: California Energy Commission

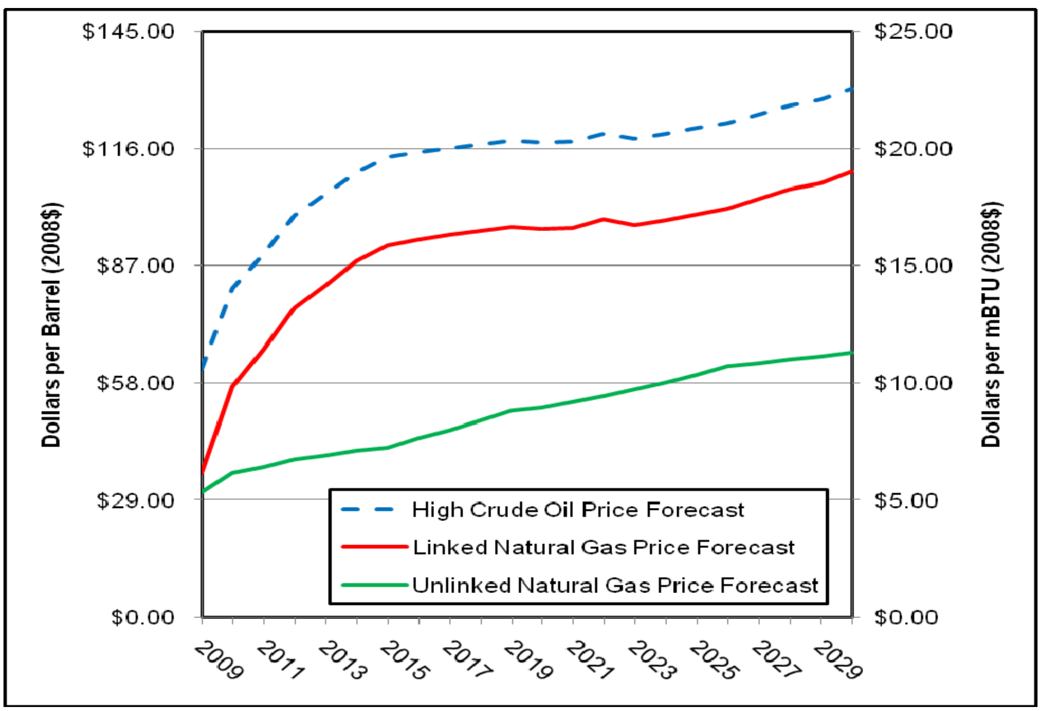
Natural Gas Transportation Fuels

There are at least two alternative views on the relationship between crude oil and natural gas prices, one that relies on a strong historical price relationship between these primary fuels, and another that delinks these prices on the basis of the increasingly optimistic natural gas supply outlook and the declining substitution between the fuels in some uses. Due to the uncertainty in the long-term relationship between crude oil and natural gas commodity prices, CNG, LNG, and hydrogen transportation fuel price forecasts were developed as price bands based on four distinct natural gas commodity price forecasts, and associated with the high and low crude oil price cases. The high boundary of each price band is linked to crude oil price forecasts, and the low boundaries are unlinked to crude oil price cases and use alternative natural gas price forecasts used within the Energy Commission. Staff developed these high and low price bands for natural gas prices using different methods or forecasts available to the Energy Commission. Natural gas commodity prices in the following discussion refer to the natural gas prices at Henry Hub.

The natural gas price band associated with the High Crude Oil Price Case is thus bounded by a high (linked) natural gas price and a lower (unlinked) natural gas price. The upper boundary was calculated from the historical 2006-2008 cost differential between California petroleum and natural gas prices and is referred to as the "high oil price linked" natural gas price. The lower unlinked natural gas price is the same as the reference natural gas price forecast developed for the *2007 IEPR* and is referred to as the "high oil price unlinked" natural gas price. Figure B-9 illustrates the projected range of natural gas prices associated with the High Oil Price Case.

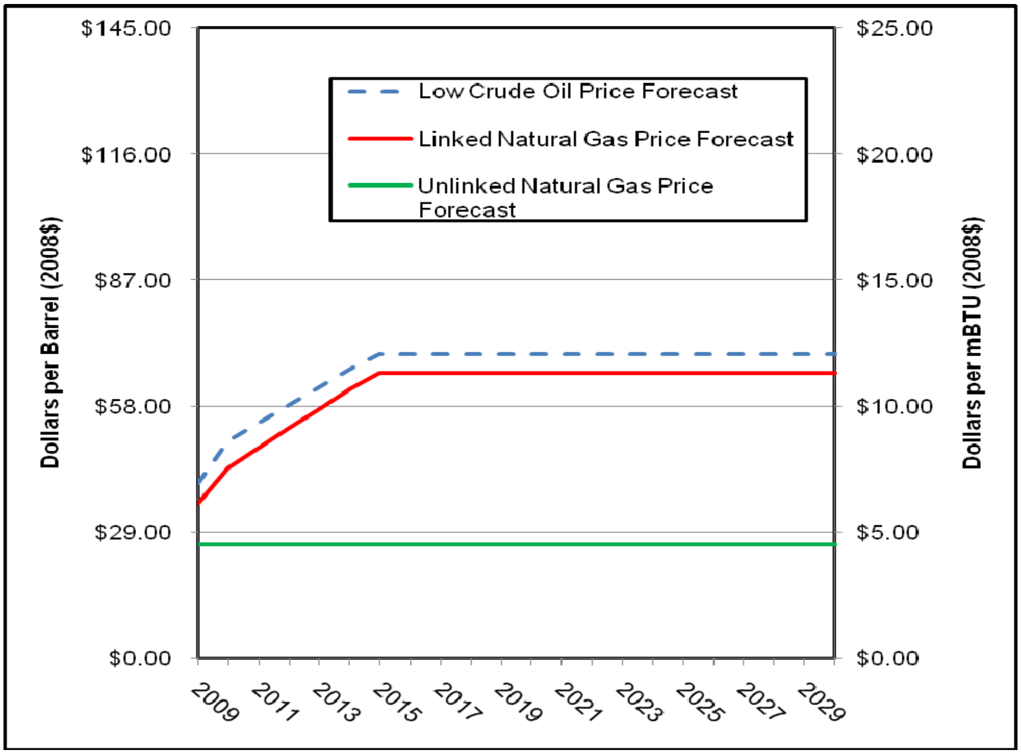
Similarly, the upper boundary of the low natural gas price band is linked to the low crude oil price case, and the lower boundary is unlinked to crude oil price. More specifically, the upper boundary forecast was adapted from an existing "High Gas Forecast Scenario"[162] used in the *2007 IEPR*, with revisions made to the early years to reflect current market prices and very minor adjustments in mid-term years, as well as extension beyond 2020, to conform to the trends assumed for the Low Crude Oil Price Case. This is referred to as the "low oil price linked" natural gas price forecast. For the lower boundary of natural gas prices, staff assumed the low natural gas price forecast for 2009 (per the U.S. EIA *Short Term Energy Outlook* projection of the 2009 natural gas price as of March 2009) will remain the same over the entire forecast period. This is referred to as the "low oil price unlinked" natural gas price forecast. Figure B.10 illustrates the range of natural gas prices associated with the Low Oil Price Case. Table B.5 presents the data illustrated in Figures B.9 and B.10 which has been used in forecasting CNG, LNG, and hydrogen prices.

Figure B.9: High Crude Oil Price Case: Range of Natural Gas Prices (2008 cents per gallon)



Source: California Energy Commission

Figure B.10: Low Crude Oil Price Case: Range of Natural Gas Prices (2008 cents per gallon)



Source: California Energy Commission

Table B.5: *IEPR 2009* Henry Hub Natural Gas Price Projections and the Energy Commission Crude Oil Price Forecasts (2008 cents per gallon)

Year	Dollars per Barrel		High Crude Oil Case, Dollars per mBTU		Low Crude Oil Case, Dollars per mBTU	
	High Crude Oil Price Forecast	Low Crude Oil Price Forecast	Linked Natural Gas Forecast	Unlinked Natural Gas Forecast	Linked Natural Gas Forecast	Unlinked Natural Gas Forecast
2009	$61.49	$40.09	$6.15	$5.33	$6.15	$4.51
2010	$81.37	$49.96	$9.84	$6.15	$7.58	$4.51
2011	$89.77	$54.14	$11.41	$6.40	$8.36	$4.51
2012	$99.49	$58.31	$13.21	$6.75	$9.13	$4.51
2013	$104.64	$62.48	$14.17	$6.91	$9.91	$4.51
2014	$110.11	$66.65	$15.19	$7.10	$10.68	$4.51
2015	$113.85	$70.00	$15.88	$7.23	$11.31	$4.51
2016	$115.15	$70.00	$16.13	$7.66	$11.31	$4.51
2017	$116.16	$70.00	$16.31	$7.98	$11.31	$4.51
2018	$117.05	$70.00	$16.48	$8.39	$11.31	$4.51
2019	$118.02	$70.00	$16.66	$8.81	$11.31	$4.51
2020	$117.54	$70.00	$16.57	$8.94	$11.31	$4.51
2021	$117.83	$70.00	$16.63	$9.20	$11.31	$4.51
2022	$119.69	$70.00	$16.97	$9.46	$11.31	$4.51
2023	$118.50	$70.00	$16.75	$9.73	$11.31	$4.51
2024	$119.62	$70.00	$16.96	$10.01	$11.31	$4.51
2025	$120.98	$70.00	$17.21	$10.37	$11.31	$4.51
2026	$122.20	$70.00	$17.44	$10.73	$11.31	$4.51
2027	$124.47	$70.00	$17.86	$10.87	$11.31	$4.51
2028	$126.62	$70.00	$18.26	$11.01	$11.31	$4.51
2029	$127.95	$70.00	$18.51	$11.17	$11.31	$4.51
2030	$130.71	$70.00	$19.02	$11.32	$11.31	$4.51

Source: California Energy Commission

Each natural gas-based alternative fuel (CNG, LNG, and hydrogen) has a price forecast based on one of these four distinct natural gas commodity price forecasts. Each fuel price forecast will utilize the same dealer and retailer margins outlined in the *Transportation Fuel Price and Demand Forecasts* staff report discussed at the February 10, 2009 staff workshop.[163] Tables B-6 and B-7 provide CNG, LNG, and hydrogen price forecasts for 2009-2030. CNG prices are also illustrated in Figures B.11 and B.12.

Table B.6: High Crude Oil Price Case, California Natural Gas-Based Alternative Transportation Fuel Price Forecasts (2008 cents per gallon)

Year	Linked (high) Price Cases			Unlinked (low) Price Cases		
	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)
2009	461	243	213	448	233	196
2010	516	288	287	461	239	213
2011	540	306	319	465	242	218
2012	567	328	356	470	246	225
2013	581	340	375	472	248	228
2014	596	352	396	475	250	232
2015	607	361	410	477	252	234
2016	610	364	415	483	257	243
2017	613	366	419	488	260	250
2018	616	368	422	494	265	258
2019	618	370	426	501	270	267
2020	617	369	424	503	272	269
2021	618	370	425	506	275	274
2022	623	374	432	510	278	280
2023	620	371	427	514	281	285
2024	623	374	432	519	284	291
2025	627	377	437	524	288	298
2026	630	379	441	529	292	305
2027	636	385	450	532	294	308
2028	642	389	458	534	295	311
2029	646	392	463	536	297	314
2030	654	399	473	538	299	317

Source: California Energy Commission

Table B.7: Low Crude Oil Price Case, California Natural Gas-Based Alternative Transportation Fuel Price Forecasts (2008 cents per gallon)

Year	Linked (high) Price Cases			Unlinked (low) Price Cases		
	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)
2009	448	233	196	436	223	179
2010	482	260	242	436	223	179
2011	494	270	257	436	223	179
2012	505	279	273	436	223	179
2013	517	288	289	436	223	179
2014	529	298	304	436	223	179
2015	538	305	317	436	223	179
2016	538	305	317	436	223	179
2017	538	305	317	436	223	179
2018	538	305	317	436	223	179
2019	538	305	317	436	223	179
2020	538	305	317	436	223	179
2021	538	305	317	436	223	179
2022	538	305	317	436	223	179
2023	538	305	317	436	223	179
2024	538	305	317	436	223	179
2025	538	305	317	436	223	179
2026	538	305	317	436	223	179
2027	538	305	317	436	223	179
2028	538	305	317	436	223	179
2029	538	305	317	436	223	179
2030	538	305	317	436	223	179

Source: California Energy Commission

Transportation Electricity Rates

The final set of fuel price projections relate to vehicle electricity rates for electric vehicles (EVs) and PHEVs. Like the natural gas-based alternative fuels, there are four electricity rate forecasts for vehicle use that have been combined with the high and low crude oil price forecasts (a high and low band for each) in different price scenarios. Unlike the natural gas-based fuel prices, these rates are not determined by either the previously discussed natural gas or crude oil price forecasts.

The 2009 high price forecast for electricity was estimated at 473 cents per GGE based on the 2009 weighted average EV rate using the method described in the *Transportation Fuel Price and Demand Forecasts* staff report cited above. This price initiates the upper boundary of the electricity price ranges associated with both the crude oil price cases, the only difference being that in the High Crude Oil Price Case the electricity rate increases by 30 percent between 2010 and 2020, while in the Low Crude Oil Price Case this rate is held constant.[164] The 2009 low price for electricity is established at 180 cents per GGE, based on the lowest currently prevailing off-peak price at Pacific Gas and Electric (PG and E). This price initiates the lower boundary of the electricity price ranges associated with both crude oil price cases. Again, in the High Crude Oil Price Case the rate increases by 30 percent between 2010 and 2020, while in the Low Crude Oil Price Case the rate is held constant. It should be noted that both of these prices involve some level of subsidy for EVs and are based on the assumption that the consumer's use of electricity for EVs will not move them to the higher rate categories. Table B-8 shows the electricity price forecasts for the high and low price bands.

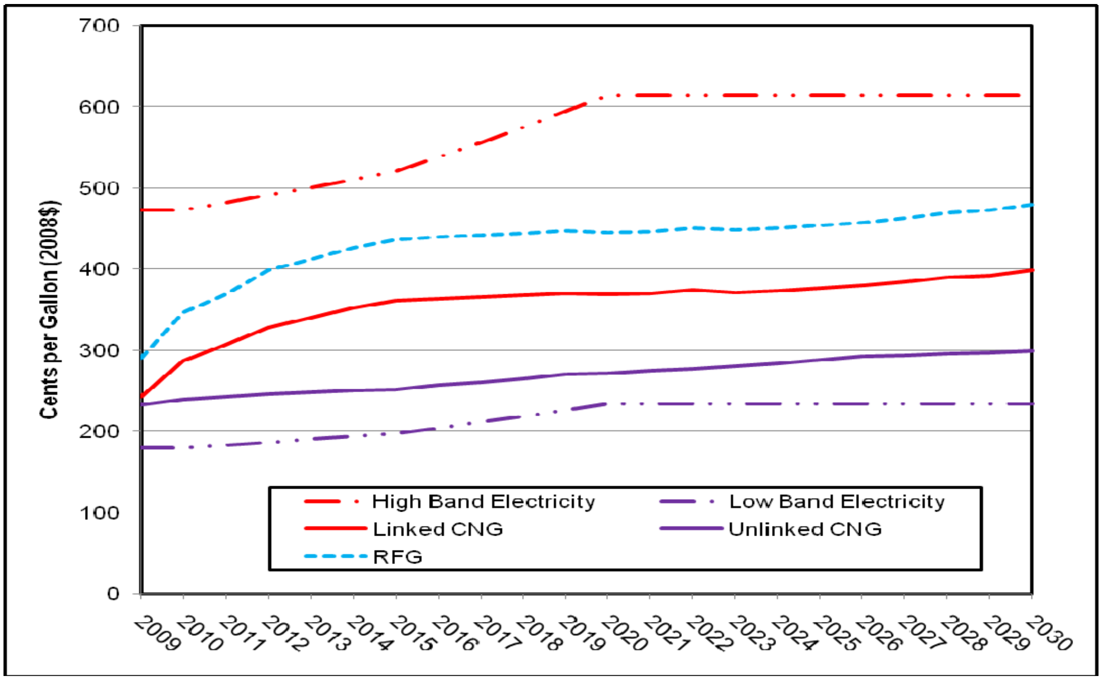
Table B.8: Electric Vehicle Electricity Price Forecasts (2008 cents per gallon)

Year	High Crude Oil Price Case		Low Crude Oil Price Case	
	High Rate	Low Rate	High Rate	Low Rate
2009	473	180	473	180
2010	473	180	473	180
2011	482	184	473	180
2012	491	187	473	180
2013	500	191	473	180
2014	510	194	473	180
2015	520	198	473	180
2016	537	205	473	180
2017	556	212	473	180
2018	575	219	473	180
2019	594	226	473	180
2020	614	234	473	180
2021	614	234	473	180
2022	614	234	473	180
2023	614	234	473	180
2024	614	234	473	180
2025	614	234	473	180
2026	614	234	473	180
2027	614	234	473	180
2028	614	234	473	180
2029	614	234	473	180
2030	614	234	473	180

Source: California Energy Commission

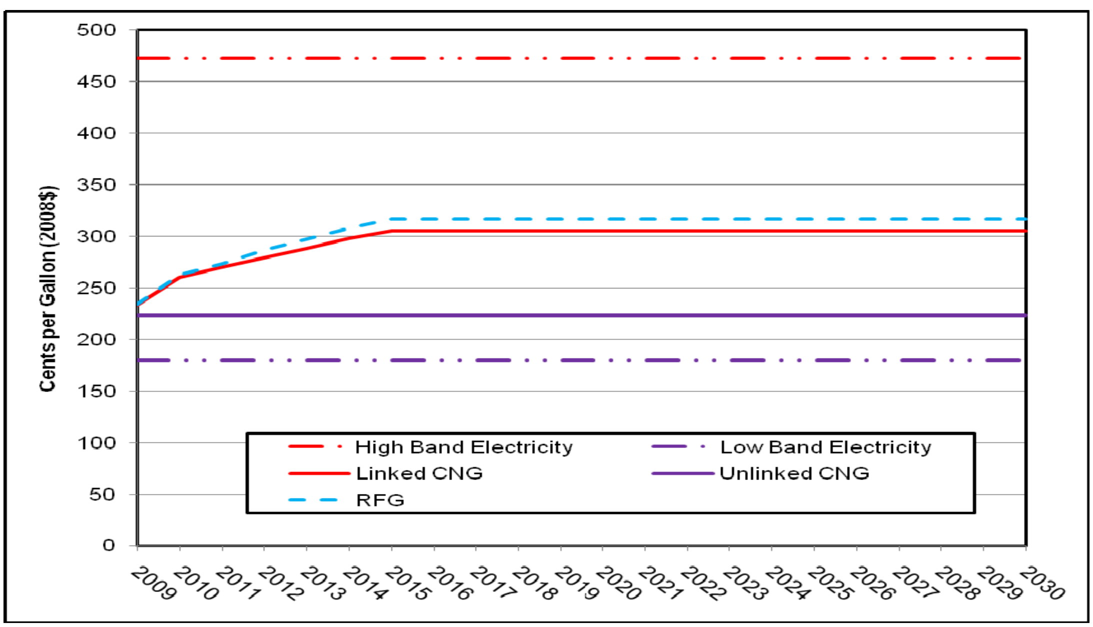
Figures B.11 and B.12 illustrate the combination of the gasoline, CNG, and electricity price forecasts corresponding to the High and Low Crude Oil Price Cases.

Figure B.11: California High Crude Oil Price Case: CNG, Electricity, and Gasoline Retail Fuel Prices (2008 cents per gallon)



Source: California Energy Commission

Figure B.12: California Low Crude Oil Price Case: CNG, Electricity, and Gasoline Retail Fuel Prices (2008 cents per gallon)



Source: California Energy Commission

GLOSSARY

AB 1007	Assembly Bill 1007
AGT	Above-ground storage tank
AOE	Annual Energy Outlook
APTA	American Public Transportation Association
ARB	California Air Resources Board
ASTM	American Society for Testing and Materials
ATA	American Trucking Association
B5	Diesel with 5 percent biodiesel content
B20	Diesel with 20 percent biodiesel content
BOE	California Board of Equalization
BPD	Barrels per day
CAFE	Corporate average fuel economy
CALCARS	California Conventional and Alternative Fuel Response Simulator
CaRFG	California Reformulated Gasoline
CARBOB	California reformulated blendstock for oxygenate blending
CBI	Caribbean Basin Initiative
CCR	Continuous catalyst regeneration
CDFA	California Department of Food and Agriculture
CFP	Clean Fuels Project
CI	Carbon intensity
CNG	Compressed natural gas
CPG	Cents per gallon
CVS	California Vehicle Survey
DGS	Distillers grain with solubles
DMS	Division of Measurement Standards

DMV	California Department of Motor Vehicles
DOF	California Department of Finance
E6	Gasoline with 6 percent ethanol content
E10	Gasoline with 10 percent ethanol content
E85	Fuel with 85 percent ethanol content, 15 percent gasoline
EIS	Environmental impact statement
EISA	Energy Independence and Security Act of 2007
EPE	Empresa de Pesquisa Energetica
FAA	Federal Aviation Administration
FEVs	Full electric vehicles
FFVs	Flexible fuel vehicles
GGE	Gasoline gallon equivalent
GHG	Greenhouse gas
GIS	Geographic information system
GSP	Gross state product
GVWR	Gross vehicle weight rating
HOV	High Occupancy Vehicle
IEPR	*Integrated Energy Policy Report*
KMP	Kinder Morgan Pipeline Company
LCFS	Low Carbon Fuel Standard
LNG	Liquefied natural gas
MMS	Minerals Management Services
MTBE	Methyl tertiary butyl ether
NOI	Notice of Intent
NOPR	Notice of Proposed rulemaking
NREL	National Renewable Energy Laboratory
OCS	Outer Continental Shelf

OCSLA	Outer Continental Shelf Land Act
OEMs	Original Equipment Manufacturers
OPIS	Oil Price Information Service
PADD V	Petroleum Administration for Defense District V
PHEVs	Plug-in hybrid electric vehicles
PZEV	Partial zero emission vehicle
RAC	Refiner acquisition cost
RFS	Renewable Fuel Standard
RFS2	Renewable Fuel Standard 2
RIN	Renewable Indentification Number
RVO	Renewable volume obligation
SAE	Society of Automotive Engineers
SB 375	Senate Bill 375
SPR	Strategic Petroleum Reserve
SULEV	Super-ultra-low-emission vehicle
SWRCB	State Water Resources Control Board
TAME	Tertiary Amyl Methyl Ether
TBD	Thousand barrels per day
TEUs	Twenty foot equivalent units
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Administration
U.S. EPA	United States Environmental Protection Agency
UL	Underwriters' Laboratories
USDA	United States Department of Agriculture
UST	Underground storage tanks
UTRR	Undiscovered Technically Recoverable Resources
VLCC	Very Large Crude Carrier

VMT	Vehicle miles traveled
ZEV	Zero emission vehicle

End Notes

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[1] *Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report*, Final Staff Report; September 2007. Report can be found at http://www.energy.ca.gov/2007publications/ENERGY COMMISSION-600-2007-009/ENERGY COMMISSION-600-2007-009-SF.PDF

[2] DMV Registration Database, File passes for 2001 to 2008.

[3] Total cargo containers handled by all the ports in the continental United States (excludes totals for Alaska, Hawaii, Guam, and Puerto Rico) during 2008 amounted to 38,932,828 twenty-foot equivalent units (TEUs). The ports of Long Beach, Los Angels, and Oakland handled 16,436,354 TEUs for the same year. Data provided by the American Association of Port Authorities (AAPA), Port Industry Statistics. Information available from http://www.aapa-ports.org/Industry/content.cfm?ItemNumber=900&navItemNumber=551; Internet; accessed on August 7, 2009. Complete data for all North American ports for the years 1990 through 2008 available from http://aapa.files.cms-plus.com/Statistics/CONTAINERTRAFFICNORTHAMERICA1990%2D2008.xls; Internet; accessed on August 7, 2009.

[4] Annual statistics are also available for the ports of Hueneme and San Diego, but no recent monthly figures. However, these two ports represent approximately 0.7 percent of total port container activity in the state and the exclusion of their data from the TEU, and diesel fuel comparison is not of significant consequence.

[5] The numbers of TEUs (imports, exports, full, and empty) processed by the ports of Long Beach, Los Angeles, and Oakland averaged 49,468 TEUs in 2007, 44,908 in 2008, and 35,810 during the first six months of 2009. Container statistics for the Port of Long Beach are available from http://www.polb.com/economics/stats/default.asp; Internet; accessed on August 7, 2009. Container statistics for the Port of Los Angeles are available from http://www.portoflosangeles.org/maritime/stats.asp; Internet; accessed on August 7, 2009. Container statistics for the Port of Oakland are available from http://www.portofoakland.com/maritime/facts_cargo.asp; Internet; accessed on August 7, 2009.

[6] *Weekly Traffic of Major U.S. Railroads For the Week Ending August 1, 2009*, Association of American Railroads; available from http://www.aar.org/NewsAndEvents/PressReleases/2009/08_WTR/~/media/AAR/Weekly_Traffic_Reports/Week30.ashx; Internet; accessed on August 6, 2009.

[7] *ATA Truck Tonnage Index Fell 2.4 Percent in June*, American Trucking Association (ATA) press release, July 27, 2009; available from http://www.truckline.com/pages/article.aspx?id=567%2F{8E1C7279-ED27-4C03-B189-CEEEE26BBB12}: Internet; accessed on August 6, 2009.

[8] *April 2009 Airline Traffic Data: System Traffic Down 5.6 Percent in April from 2008 and Down 9.1 Percent for January-to-April*, U.S. Department of Transportation, Bureau of Transportation Statistics (BTS) press release, July 16, 2009, page 1; available from http://www.bts.gov/press_releases/2009/bts034_09/pdf/bts034_09.pdf; Internet; accessed on August 6, 2009.

[9] *A Long-Term Look at California Taxable Sales and Personal Income Growth*, California State Board of Equalization, Economic Perspective, May 2002, Chart II-1, page 4; available from http://www.boe.ca.gov/news/pdf/ep5-02.pdf; Internet; accessed on August 5, 2009.

[10] A link to the BOE website containing taxable gasoline and diesel fuel sales figures for the last ten years is as follows: http://www.boe.ca.gov/sptaxprog/spftrpts.htm

[11] California gasoline demand for the first four months of 2009 averaged 40.52 million gallons per day compared to an average of 41.38 million gallons per day for the same period in 2008. For the most recent 12-month period, gasoline demand has averaged 40.47 million gallons per day compared to the previous 12-month average of 42.43 million gallons per day.

[12] California diesel fuel demand for the first three months of 2009 averaged 8.23 million gallons per day compared to an average of 8.92 million gallons per day for the same period in 2008. For the most recent 12-month period, diesel fuel demand has averaged 9.20 million gallons per day compared to the previous 12-month average of 10.25 million gallons per day.

[13] *Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report* available at: http://www.energy.ca.gov/2007publications/ENERGY COMMISSION-600-2007-009/ENERGY COMMISSION-600-2007-009-SF.PDF

[14] *State Alternative Fuels Plan*, California Air Resources Board and California Energy Commission; December 2007; Document number ENERGY COMMISSION-600-2007-011-CMF; available at http://www.energy.ca.gov/2007publications/ENERGY COMMISSION-600-2007-011/ENERGY COMMISSION-600-2007-011-CMF.PDF

[15] Wikipedia, "Ford Model T"; available from http://en.wikipedia.org/wiki/Ford_Model_T; Internet; accessed on July 31, 2009.

[16] U.S. General Accounting Office, *Importance and Impact of Federal Alcohol Fuel Tax Incentives*, GAO/RCED-84-1, Washington D.C.: Government Printing Office, 1984, page 1. A link to the document is as follows: http://archive.gao.gov/d6t1/124476.pdf

[17] Ibid, page1.

[18] Ibid, pages 4-5. The initial primary federal legislative acts addressing ethanol blending exemption from a portion of the federal excise taxation rates on gasoline included: the Energy Tax Act of 1978 (Public Law 95-618, Nov. 9, 1978); the Crude Oil Windfall Profit Tax Act of 1980 (Public Law 96-223, Apr. 2, 1980); and the Highway Revenue Act of 1982 (Public Law 97-424-Title V, Jan. 6, 1983).

[19] 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. A link to the document is as follows: http://www.arb.ca.gov/fuels/gasoline/pub/oxyrprt.pdf

[20] 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 RFG geographic regions of the state. A link to the Final Rule is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/1996/November/Day-13/pr-23839DIR/Other/fuel.txt.html

[21] The California Air Resources Board adopted reformulated gasoline regulations on November 22, 1991, referred to as CaRFG Phase 2 regulations. A link to the staff report is as follows: http://www.arb.ca.gov/fuels/gasoline/carfg2/carfg2.pdf

[22] 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 (Energy Commission) to "develop a timetable for the removal of MTBE from California gasoline not later than December 31, 2002." A copy of the Executive Order may be viewed at the following link: 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. The link to a copy of this report is as follows: 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. A link to a copy of that Executive Order is as follows: http://www.calgasoline.com/EOD52-02.PDF

[23] *MTBE Contamination From Underground Storage Tanks*, Government Accountability Office, GAO-02-753T, May 21, 2002. This report provides an overview of the drinking water contamination concerns and evolution of various sate actions. A copy of the document may be accessed at the following link: http://www.gao.gov/new.items/d02753t.pdf

[24] United States Environmental Protection Agency, *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule*, Federal Register, Vol. 74, No. 99, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[25] United States Environmental Protection Agency, *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Extension of Comment Period*, Federal Register, Vol. 74, No. 128, pp. 32091-02, July 7, 2009. A link to the document is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2009/July/Day-07/a15947.pdf

[26] United States Environmental Protection Agency, *Renewable Fuel Standard for 2009, Issued Pursuant to Section 211(o) of the Clean Air Act*, Federal Register, Vol. 73, No. 226, November 21, 2008. A link to the document is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2008/November/Day-21/a27613.pdf

To quote from the specific portion of the regulation from page 70643:

"This standard is calculated as a percentage, by dividing the amount of renewable fuel that the Act requires to be used in a given year by the amount of gasoline expected to be used during that year, including certain adjustments specified by the Act. In this notice we are publishing an RFS of 10.21% for 2009. This standard is intended to lead to the use of 11.1 billion gallons of renewable fuel in 2009, as required by the Energy Independence and Security Act of 2007 (EISA). As discussed below, we expect the 11.1 billion gallons of renewable fuel required in 2009 to include approximately 0.5 billion gallons of biodiesel and renewable diesel."

[27] United States Environmental Protection Agency, *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule*, Federal Register, Vol. 74, No. 99, page 24953, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

To quote from the specific portion of the regulation:

"In order for an obligated party to demonstrate compliance, the percentage standards would be converted into the volume of renewable fuel each obligated party is required to satisfy. This volume of renewable fuel is the volume for which the obligated party is responsible under the RFS program, and would continue to be referred to as its Renewable Volume Obligation (RVO). Since there would be four separate standards under the RFS2 program, there would likewise be four separate RVOs applicable to each refiner, importer, or other obligated party."

[28] Energy Information Agency (EIA) Supply and Consumption Figures, June 2009.

[29] *Annual Energy Outlook 2009*, Energy Information Administration, DOE/EIA-0383(2009), March 2009. A link to the report is as follows: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf. The revised Reference Case was released in April of 2009.
A link to that information is as follows: http://www.eia.doe.gov/oiaf/servicerpt/stimulus/index.html Table 11 contains the EIA projections for gasoline and diesel fuel.

[30] *Mid-Level Blend Ethanol: Challenges, Opportunities & Testing Follow Through,* James Frusti, Chrysler LLC, Joint IEPR and Transportation Committee Workshop on Transportation Fuel Infrastructure Issues, California Energy Commission, Sacramento, California, April 14-15, 2009. A copy of this presentation may be viewed at the following link: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/09-Frusti_James_Mid-Level_Ethanol_Blends.pdf

[31] University of Minnesota, Department of Mechanical Engineering, *Demonstration and Driveability Project to Determine the Feasibility of Using E20 as a Motor Fuel,* November 4, 2008, [http://www.mda.state.mn.us/news/publications/renewable/ethanol/e20drivability.pdf].

[32] Oak Ridge National Laboratory, *Effects of Intermediate Ethanol Blends on Legacy Vehicles and Small Non-Road Engines, Report 1*, publication number ORNL/TM-2008/117, October 2008, [http://feerc.ornl.gov/publications/Int_blends_Rpt_1.pdf].

[33] Deadline for submitting comments on the E15 waiver request was extended from May 21 to July 20, 2009. *Notice of Receipt of a Clean Air Act Waiver Application To Increase the Allowable Ethanol Content of Gasoline to 15 Percent; Extension of Comment Period*, Federal Register, Vol. 74, No. 96, May 20, 2009, page 23704. A link to the notice is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2009/May/Day-20/a11785.pdf

[34] All of these registered vehicles (381,584) were in the light-duty class. The majority of these FFVs were either a variation of some type of sport utility vehicles (34.5 percent), pickup trucks (32.1 percent) or vans (15.1 percent).

[35] Staff estimates that there are a total of between 217,000 and 252,000 meters at nearly 10,000 retail fuel stations throughout California. On average, each meter is estimated as having dispensed between 75,000 and 87,500 gallons of transportation fuel during the period July 1, 2007, through June 30, 2008. Further assuming that a dispenser designed to dispense only one type of fuel would be equipped with two meters, the average fuel distribution during this period for such a dispenser is calculated at between 150,000 and 185,000 gallons. The lower estimate for number of meters at retail motor fuel locations originated from the California Division of Measurement Standards, County Monthly Report (CMR) summary for period July 1, 2007, through June 30, 2008. The higher estimate was derived by staff as part of its work associated with the Fuel Temperature study. As a point of reference, it is further estimated that each fuel dispenser in California distributed an average of 452,000 gallons of transportation fuel over the same period of time. The average distribution level is significantly higher than the "single-fuel" dispenser average because most dispensers are designed to sell three grades of gasoline and will include six meters per dispenser, rather than two. Dispensers that also sell diesel fuel (along with the three grades of gasoline) will normally have eight meters per dispenser (four for each side or face).

[36] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory, Technical Report NREL/TP-540-41590, December 2007, page 20. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[37] A link to a description of this Authorization Suspension of E85 dispenser components is as follows: http://www.ul.com/global/eng/pages/offerings/perspectives/regulator/e85info/suspension/

[38] Underwriters Laboratories Announces Development of Certification Requirements for E85 Dispensers, UL press release, October 16, 2007. A link to this press release is as follows: http://www.ul.com/global/eng/documents/offerings/perspectives/regulators/e85/e85certificationrequirements.pdf

[39] As of November 2007, UL had yet to receive any fueling hose assemblies for E85 compatibility testing. Refer to the following presentation: *E85 Dispensing Equipment Update*, Dennis A. Smith, US Dept of Energy, November 17, 2008, slides 7-8. A link to this presentation is as follows: http://www1.eere.energy.gov/cleancities/toolbox/pdfs/uldoe.pdf

[40] National Association of Convenience Stores (NACS) and the Society of Independent Gasoline Marketers of America (SIGMA), Letter to Congress, March 27, 2006, page 2. A copy of the document may be accessed at the following link: http://www.sigma.org/pdf/E85-Mandates.pdf. According to the National Commission on Energy Policy's (NCEP) recent report: "Replacing an entire system can be expected to cost substantially more than $150,000 per facility depending upon the market." *Task Force on Biofuels Infrastructure*, NCEP, May 2009, Appendix B, page 53; available from http://www.energycommission.org/ht/a/GetDocumentAction/i/10232; Internet; accessed on August 2,

2009. Additional cost estimates for both new and retrofit scenarios are provided in the following brief paper: *Cost of Adding E85 Fueling Capability to Existing Gasoline Stations: NREL Survey and Literature Search,* National Renewable Energy Laboratory, Publication NREL/FS-540-42390, March 2008. A link to this document is as follows: http://www.afdc.energy.gov/afdc/pdfs/42390.pdf

[41] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory, Technical Report NREL/TP-540-41590, December 2007, Appendix C, page 41. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[42] *Fuel Delivery Temperature Study*, California Energy Commission, ENERGY COMMISSION-600-2009-002-CMF, page 59. A link to this study is as follows: http://www.energy.ca.gov/2009publications/ENERGY COMMISSION-600-2009-002/ENERGY COMMISSION-600-2009-002-CMF.PDF

[43] Based on data for 2008, 56 percent of the convenience stores were owned and operated by someone who only had one station. A link to this information and more is at the following link: http://www.nacsonline.com/NACS/News/Campaigns/GasPrices_2009/Pages/WhoSellsGas.aspx

[44] National Association of Convenience Stores, NACS Online, Fact Sheets, Motor Fuels, Motor Fuel Sales, posted May 15, 2009. A link to the fact sheet is as follows: http://www.nacsonline.com/NACS/News/FactSheets/Motor%20Fuels/Pages/MotorFuelSales.aspx

[45] National Association of Convenience Stores, *NACS State of the Industry Report of 2007 Data* (1998 – 2007 data), December 2008 and 2009 press release (2008 data). Press release: *Convenience Store Sales, Profits Showed Gains in 2008*, NACS, April 7, 2009. A link to the press release is as follows: http://www.nacsonline.com/NACS/NEWS/PRESS_RELEASES/2009/Pages/PR040709.aspx

[46] One such example of government funding is the California Air Resources Board Alternative Fuel Incentive Program created through Assembly Bill 1811. This activity was designed to provide $25 million "for the purposes of incentivizing the use and production of alternative fuels." A link to the ARB site is as follows: http://www.arb.ca.gov/fuels/altfuels/incentives/incentives.htm.

An example of a specific station in Brentwood that received grant money from this program (approximately $580,000) is as follows: *California Has New E85 Station Open to the Public*, Dimitri Stanich, California Air Resources Board, February 26, 2008. A link to the press release is as follows: http://www.arb.ca.gov/newsrel/nr022608.htm. The list of additional California programs that may provide other funding opportunities for prospective E85 retail station owners can be viewed at the following link: http://www.afdc.energy.gov/afdc/progs/state_summary.php/CA

Finally, the 2009 American Recovery and Reinvestment Act (Section 1123) provides for a tax credit of up to $50,000 per business through 2010 that can be applied to the installation of E85 dispensers. The specific language to the Section 1123 provisions are found on page 47 at the following link: http://thomas.loc.gov/home/h1/Recovery_Bill_Div_B.pdf

[47] *Mid-Level Blend Ethanol: Challenges - Opportunities & Testing Follow Through*, James Frusti, Chrysler, April 14, 2009, slide 11. A link to this presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/09-Frusti_James_Mid-Level_Ethanol_Blends.pdf

[48] *GM Update on Flex-Fuel Vehicle Challenges in CA*, James Ehlmann and Clay Okabayashi, General Motors, June 24, 2008, slides 4 through 8. A link to this presentation is as follows: http://www.netl.doe.gov/publications/proceedings/08/clean-cities-ca/pdfs/6.24Tues/Ehlmann%20%26%20Okabayashi%20-%20GM.pdf

[49] Ibid., slide 9.

[50] *The California Low-Emission Vehicle Regulations - With Amendments Effective April 17, 2009*, California Air Resources Board. A link to this document is as follows: http://www.arb.ca.gov/msprog/levprog/cleandoc/cleancomplete_lev-ghg_regs_3-09.pdf

The revised Zero Emission Vehicle standards describe the multiple and complex compliance options for vehicle manufacturers. Some of these compliance pathways can include the increased sales of PZEVs. Hearing Date: 03/27/08, Adopted: 12/17/08. A link to this Final Regulation Order – Part 5 is as follows: http://www.arb.ca.gov/regact/2008/zev2008/zfrop5.pdf

For a historical summary of the ZEV regulation evolution, please refer to the following document: *Learning from California's Zero-Emission Vehicle Program*, Louise Wells Bedsworth and Margaret R. Taylor, California Economic Policy, Volume 3, Number 4, September 2007. A link to the document is as follows: http://www.ppic.org/content/pubs/cep/EP_907LBEP.pdf

[51] *California State Motor Vehicle Pollution Control Standards; Notice of Decision Granting a Waiver of Clean Air Act Preemption for California's 2009 and Subsequent Model Year Greenhouse Gas Emission Standards for New Motor Vehicles*, U.S. Environmental Protection Agency (EPA), Federal Register, Vol. 74, No. 129 / Wednesday, July 8, 2009. A link to this publication is as follows: http://edocket.access.gpo.gov/2009/pdf/E9-15943.pdf

[52] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory (NREL), Technical Report NREL/TP-540-41590, December 2007, Appendix E, page 43. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[53] *National Survey of E85 and Gasoline Prices*, P. Bergeron, National Renewable Energy Laboratory, Technical Report NREL/TP-540-44254, October 2008. According to this study, "*The E85:gasoline price ratio was always higher than the E85:gasoline energy content ratio, signifying a higher per-mile cost for E85 in comparison to that of gasoline. The disparity diminished somewhat as the price of gasoline rose above $3 per gallon.*" A link to this study is as follows: http://www.afdc.energy.gov/afdc/pdfs/44254.pdf

[54] *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program*; Proposed Rule, U.S. Environmental Protection Agency, Federal Register, Vol. 74, No. 99, May 26, 2009, pp. 24920-1. A link to the proposed rule is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[55] An overview of the RIN requirements and some of the complicating factors are contained in the following paper: *The Changing RINs Landscape*, Oil Price Information Service (OPIS), 2009. A link to a copy of this document is as follows: http://www.scribd.com/doc/17121722/Briefing-on-RINs-Renewable-Identification-Numbers

[56] A link to the California Air Resources Board website that contains background information and regulations is as follows: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

[57] The carbon intensity (CI) value for Brazilian sugarcane ethanol using average production processes is 73.40 gCO2e/MJ. This value includes both direct emissions and other indirect effects (such as changes in land use). If the Brazilian sugarcane-based ethanol production has electricity cogeneration from the burning of bagasse (sugarcane residue), the CI drops to 66.40 gCO2e/MJ. If mechanized harvesting is also included along with electricity generation, the CI value drops further to 58.20 gCO2e/MJ.

Average Midwestern ethanol produced from corn has a carbon intensity value of 99.40 gCO2e/MJ by comparison. Ethanol produced using corn at an average California facility has a carbon intensity value of between 80.70 and 88.9 gCO2e/MJ, depending on whether or not the distillers grain with solubles (DGS) co-product is wet or dry. California Air Resources Board, Modified Regulation Order, Table 6, page 43, posted July 20, 2009. A link to the document is as follows: http://www.arb.ca.gov/regact/2009/lcfs09/lcfsmodtxt.pdf

[58] 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. A copy

of this document may be accessed at the following link:
http://research.stlouisfed.org/publications/red/2009/01/Gallagher.pdf

[59] According to Ethanol Producer Magazine, as of June 26, 2009, there was 12.853 billion gallons of ethanol production capacity in the United States. However, only 10.622 billion gallons of capacity is operational, while another 1.358 billion gallons of incremental production capacity in under construction. A link to Ethanol Producer Magazine's ethanol plant capacity information is as follows:
http://www.ethanolproducer.com/plant-list.jsp?country=USA&view=

[60] RFS2 corn-based ethanol limits for 2012 are currently set to 13.2 billion gallons. Staff estimates that U.S. ethanol capacity from corn-based facilities will be at least 13.5 billion gallons by the end of 2010.

[61] Recent presentation at the Platt's Advanced Biofuels conference by Ben Thorpe indicates that there is currently 3.56 million gallons per year cellulosic ethanol production capacity operational. Another 300,000 gallons of capacity is slated to be on-line sometime in 2009, along with another 4 million gallons by mid-2010. A link to this presentation is as follows:
https://platts.com/Events/2009/pc934/presentations/Ben_Thorp.pdf

This total is far less than the 100 million gallons of cellulosic production capacity claimed by EPA in its May 26, 2009, NOPR, Table V.B.2–3, pp 24990-01. A link to the document is as follows:http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[62] *Jury returns $10.4M verdict in biofuel lawsuit*, Associated Press, June 30, 2009. A link to the article is as follows: http://www.mercurynews.com/breakingnews/ci_12723637?nclick_check=1

United States District Court for the Southern District of Alabama, Mobile County, Parsons & Whittemore Enterprises Corporation v. Cello Energy, LLC, et al, case number 1:07-cv-00743-CG-B. A link to additional information is as follows: http://www.morelaw.com/verdicts/case.asp?n=1:07-cv-00743-CG-B&s=AL&d=40517

[63] State of Oregon, Oregon Administrative Rules, Department of Agriculture, 603-027-0420, Standard Fuel Specifications, subsection (11) Biodiesel Blends Required

(a) When the production of biodiesel in Oregon from base feedstock grown or produced in Oregon, Washington, Idaho, and Montana reaches a level of at least 5 million gallons on an annualized basis for at least three months, the Department shall notify all retailers, nonretail dealers, and wholesale dealers in Oregon, in a notice that communicates,

(A) The biodiesel production in Oregon from base feedstock grown or produced in Oregon, Washington, Idaho, and Montana has reached a level of at least 5 million gallons on an annualized basis for at least three months, and

(B) Three months after the date of the notice, a retail dealer, nonretail dealer, or wholesale dealer may only sell or offer for sale diesel fuel in Oregon containing at least two percent biodiesel by volume or other renewable diesel with at least two percent renewable component by volume.

A link to these regulations is as follows:
http://arcweb.sos.state.or.us/rules/OARS_600/OAR_603/603_027.html

[64] http://www.syracuse.com/news/index.ssf/2009/05/sunoco_wins_auction_for_volney.html

[65] Harvest of sugarcane in Brazil normally begins in April and is usually completed during November.

[66] A more recent compilation of ethanol sugar and plants in Brazil from the Brazil Ministry of Agriculture indicates that there are a total of 395 facilities that produce ethanol (248 sugar/ethanol plants and 157 ethanol-only plants). Information is current as of March 13, 2009. A complete list of the individual facilities may be accessed at the following link:
http://www.agricultura.gov.br/pls/portal/docs/PAGE/MAPA/SERVICOS/USINAS_DESTILARIAS/USINAS_CADASTRADAS/UPS_13-03-2009_0.PDF

Please note that the list is in Portuguese. All sugar/ethanol facilities are referred to as "Mista," ethanol-only facilities as "Álcool," and sugar mills as "Açúcar."

[67] *An Overview of the Brazilian Sugarcane Industry*, Marcos Jank, UNICA, November 13, 2008, slide 10. A link to the presentation is as follows: http://english.unica.com.br/download.asp?mmdCode=9C382A63-916C-41E8-A4F9-381C6B60C60C

[68] The Caribbean Basin Initiative or CBI is an economic development program designed, in part, to allow specific types of goods imported into the United States duty-free or at reduced tariff structures. A lengthy 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

Ethanol imports from CBI countries may be imported into the United States duty-free at quantities no greater than 7 percent of the previous federal fiscal year U.S. fuel ethanol consumption quantity (ending September 30th). This means that fuel ethanol imports from CBI countries could amount to 620.5 million gallons in 2009 based on ethanol demand of 8.86 billion gallons between October 2007 and September 2008. See the following link for specific statute language relevant to the annual import limit that is duty-free: http://regulations.vlex.com/vid/import-investigations-ethyl-alcohol-fuel-22711676

CBI fuel ethanol imports totaled 273.4 million gallons during 2008. A more detailed description of ethanol imports from CBI countries in contained in the following report: *Ethanol Imports and the*

Caribbean Basin Initiative, Brent D. Yacobucci, CRS Report to Congress, Updated March 18, 2008. A link to that report is as follows: http://www.nationalaglawcenter.org/assets/crs/RS21930.pdf

[69] 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 26 percent by volume.

The Brazilian Ethanol Programme: Impacts on World Ethanol and Sugar Markets, Tatsuji Koizumi, Commodities and Trade Division of the Food and Agriculture Organization of the United Nations (FAO), June 24, 2003, page 2. A link to this document is as follows: ftp://ftp.fao.org/docrep/fao/006/ad430e/ad430e00.pdf

This working paper also contains a good summary of the history of Brazil's ethanol program.

[70] *Harmonized Tariff Schedule of the United States (2009) – Supplement 1*, United States International Trade Commission, July 1, 2009, subheading 2207.10.60, page 1006. Citation for the 2.5 percent ad valorem fee on undenatured ethyl alcohol intended for nonbeverage use in the United States.

Harmonized Tariff Schedule of the United States (2009) – Supplement 1, United States International Trade Commission, July 1, 2009, subheading 9901.00.50, page 2558. Citation for the secondary import tariff of 14.27 cents per liter or 54.08 cents per gallon (CPG) on ethyl alcohol intended for fuel use in the United States. A link to the Harmonized Tariff Schedule document is as follows: http://www.usitc.gov/publications/docs/tata/hts/bychapter/0910htsa.pdf

[71] *Removal of U.S. Ethanol Domestic and Trade Distortions: Impact on U.S. and Brazilian Ethanol Markets*, Amani Elobeid and Simla Tokgoz, Center for Agricultural and Rural Development, Iowa State University, Working Paper 06-WP 427, October 2006 (Revised), page 22. A link to the document is as follows: http://www.card.iastate.edu/publications/DBS/PDFFiles/06wp427.pdf

The lower estimate of 2.4 percent U.S. ethanol price reduction is from the following Working Paper: *The Economics of U.S. Ethanol Import Tariffs with a Consumption Blend Mandate and Tax Credit*, Harry de Gorter and David R. Just, Department of Applied Economics and Management, Cornell University, Ithaca, New York, February 7, 2008, Table 2, page 24. Note that the 2.4 percent reduction of the U.S. ethanol price is for 2015 and is under a scenario of mandated ethanol use, removal of the import tariff, and retention of the 45 cpg ethanol blenders' tax credit. A link to this Working Paper is as follows: http://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID1097106_code328474.pdf?abstractid=1024532&mirid=5

[72] *Perspectivas Para O Etanol No Brasil*, Empresa de Pesquisa Energética (EPE), October 3, 2008. A link to this document in Portuguese is as follows: http://www.epe.gov.br/Petroleo/Documents/Estudos_28/Cadernos%20de%20Energia%20-%20Perspectiva%20para%20o%20etanol%20no%20Brasil.pdf

The EPE ethanol export forecast is from Graph 9 on page 33 of this report. The UNICA export estimate is from Table 7 on page 38 of the report.

[73] *Biofuels Roundup: Brazilian Ethanol Gets Japanese Boost*, Jeff St. John, Greentech Media, September 30, 2008. A link to the article is as follows: http://www.greentechmedia.com/articles/read/biofuels-roundup-brazilian-ethanol-gets-japanese-boost-1505/

The demand for Brazilian ethanol imports for Japan is estimated at up to 1.8 billion liters or 480 million gallons by 2010. *Japan's Ethanol Introduction and Outstanding Issues*, Japan's Institute of Energy Economics, October 2007, page 4. A link to this document is as follows: http://eneken.ieej.or.jp/en/data/pdf/403.pdf

[74] The Lomita facility was averaging 22,300 barrels per day of ethanol receipts during 2007 according Kinder Morgan. See *Biofuels Houston Summit III* presentation, October 20-21, 2008, slide 20. A link to this presentation is as follows:
http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

Staff estimates that rail imports of fuel ethanol for all of Southern California totaled approximately 33,500 barrels per day during 2007. Total fuel ethanol dmand in Southern California for that year was about 34,700 barrels per day.

[75] Staff discussion concerning proposed project with company representatives.

[76] 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

[77] *Biofuels Houston Summit III* presentation, Kinder Morgan, October 20-21, 2008, slide 20. A link to this presentation is as follows:
http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

[78] *Renewable Fuel Terminal Infrastructure*, Rahul Iyer, Primafuel, California Energy Commission Workshop, April 14, 2009, slide 8. A copy of this presentation is as follows:
http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/05-Lyer_Rahul_Primafuel_ENERGY COMMISSION_EnergyInfrastructureWorkshop.pdf

[79] *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: http://phx.corporate-ir.net/phoenix.zhtml?c=119776&p=irol-newsArticle&ID=1231520&highlight=

[80] *Joint Integrated Energy Policy Report 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

[81] POET Joins Magellan Midstream Partners to Assess Dedicated Ethanol Pipeline, Magellan Midstream Partners, L.P. press release, March 16, 2009. A link to this press release is as follows: http://www.magellanlp.com/news/2009/20090316_5.htm

[82] *USDA Agricultural Projections to 2018,* Report Number OCE-2009-1, February 2009, Table 8, page 33. A copy of the document may be accessed at the following link:

http://www.ers.usda.gov/Publications/OCE091/OCE091.pdf

[83] Ibid., quote from page 18, "Projections for field crops reflect provisions of the Food, Conservation, and Energy Act of 2008 (2008 Farm Act), which are assumed to continue through the projection period. An important change in the 2008 Farm Act was the reduction in the maximum acreage enrollment in the Conservation Reserve Program (CRP). Rather than the previous cap on enrollment of 39.2 million acres, the new farm legislation sets the maximum at 32 million acres, beginning on October 1, 2009. With CRP enrollment at 34.8 million acres on September 30, 2008, ***this policy change provides some additional cropland for potential use in production rather than tightening cropland availability over the projection period***."

[84] Ibid. Table 7, page 32.

[85] *Historical Perspectives On Vegetable Oil-based Diesel Fuels*, Gerhard Knothe, Inform, Volume 12, November 2001, pp. 1103-4. A link to this article is as follows: http://www.biodiesel.org/resources/reportsdatabase/reports/gen/20011101_gen-346.pdf

[86] Ibid. page 1107.

[87] Ibid. page 1105.

[88] National Renewable Energy Laboratory, *Biodiesel Handling and Use Guide*, fourth edition, publication number NREL/TP-540-43672, revised January 2009, page 23. A link to the revised document is as follows: http://www.nrel.gov/docs/fy09osti/43672.pdf

[89] 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 2004, pages 18, 49, and 50. A link to the survey is as follows: http://www.nrel.gov/docs/fy06osti/38836.pdf

[90] The $1 per gallon volumetric biodiesel blenders 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. The following link to a National Biodiesel Board Issue Brief contains additional specifics and Internal Revenue Service provisions: http://www.biodiesel.org/news/taxincentive/Biodiesel%20Tax%20Credit%20NBB%20Issue%20Breif.pdf

[91] European Biodiesel Board press release, Figure II, page 2, July 15, 2009. A link to the press release is as follows: http://www.ebb-eu.org/EBBpressreleases/EBB%20press%20release%202008%20prod%202009%20cap%20FINAL.pdf

[92] The European Commission conducted a nine-month investigation and concluded that the application of countervailing and anti-dumping tariffs for U.S. biodiesel exports to Europe was necessary to “level the playing field” for European biodiesel producers. The new tariffs became effective on March 13, 2009. On July 1, 2009, the Council of the European Union adopted these provisions for a period of five years. A link to the countervailing tariff decision is as follows:
http://register.consilium.europa.eu/pdf/en/09/st11/st11080.en09.pdf

The link to the anti-dumping tariff decision is as follows:
http://register.consilium.europa.eu/pdf/en/09/st11/st11084.en09.pdf

[93] However, some biodiesel producers and exporters soon realized that the addition of even small quantities of petroleum diesel fuel (approximately 1 percent by volume) enabled them to obtain the blenders credit for nearly all of the export volume. The increased exports of biodiesel originating from the United States prompted the decision by the European Union to impose sufficiently high off-setting tariffs to help ensure a more level playing field for their own biodiesel producers. A copy of the press release from the European Biodiesel Board is as follows:
http://www.ebbeu.org/EBBpressreleases/PR%20B99%20publication%20definitive%20measures%20%20070709.pdf

[94] 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

[95] Conversion of waste oils (used cooking oil) to biodiesel has a carbon intensity value of 13.70 gCO2e/MJ. Conversion of tallow to renewable diesel fuel has a carbon intensity value of 27.70 gCO2e/MJ. California Air Resources Board, Modified Regulation Order, Table 7, page 44, posted July 20, 2009. A link to the document is as follows: http://www.arb.ca.gov/regact/2009/lcfs09/lcfsmodtxt.pdf

[96] Biodiesel magazine, plant list. A link to this information is as follows: http://www.biodieselmagazine.com/plant-list.jsp?country=USA&view=

[97] Ibid.

[98] *EU Biodiesel Potential*, Raffaello Garofalo, RSB Consultation, Europe Stakeholder Outreach Meeting, Brussels, March 19, 2009, slide 8. A link to this presentation is as follows: http://cgse.epfl.ch/webdav/site/cgse/shared/Biofuels/Regional%20Outreaches%20&%20Meetings/2009/Europe%2009/Raffaello%20Garofalo%20-%20EBB.pdf

[99] European Biodiesel Board press release, Figure V, July 15, 2009, page 3. A link to this document is as follows: http://www.ebb-eu.org/EBBpressreleases/EBB%20press%20release%202008%20prod%202009%20cap%20FINAL.pdf

[100] 403 million gallons based on B10 levels for total diesel fuel demand of 4.03 billion gallons per year by 2022 and 806 million gallons based on B20.

[101] Estimates from Cybus Capital Markets LLC range from 2 cents per gallon (cpg) for pipeline transportation, 5 cpg via barge, 10 cpg via rail, and 20 cpg via tanker truck. *Biofuels Houston Summit III* presentation, Kinder Morgan, October 20-21, 2008, slide 23. A link to this presentation is as follows: http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

[102] *KMP Completes First Commercial Shipment of Biodiesel in U.S. on Plantation Pipe Line*, Kinder Morgan press release, June 30, 2009.A link to this press release is as follows: http://phx.corporate-ir.net/phoenix.zhtml?c=119776&p=irol-newsArticle&ID=1303436&highlight=

[103] U.S. Energy Information Administration, *2008 Annual Energy Report*, Table 6.5. Natural Gas Consumption by Sector, 1949- 2007. http://www.eia.doe.gov/emeu/aer/txt/ptb0605.html

[104] U.S. Department of Energy via: http://www.fueleconomy.gov/feg/bifueltech.shtml

[105] All carbon intensity values come from the ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1.*

[106] For this discussion, dual fuel CNG/gasoline vehicles are considered as CNG vehicles in vehicle counts. All vehicle counts come via the DMV database.

[107] Information from Fueleconomy.com: http://www.fueleconomy.gov/feg/bifueltech.shtml

[108] State Alternative Fuels Plan - AB 1007 Report - Docket # 06-AFP-1, http://www.energy.ca.gov/ab1007/index.html

[109] http://www.socalgas.com/business/ngv/refueling.html

[110] http://www.pge.com/myhome/environment/pge/cleanair/naturalgasvehicles/fueling/

[111] Southern California Gas Company: http://www.socalgas.com/business/ngv/homefueling.html

[112] Testimony of Michael Eaves at the April 14, 2009, Joint Committee Workshop, California Energy Commission at http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[113] All carbon intensity values come from the ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1.*

[114] ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1.* Table ES-10

[115] Testimony of Robert Graham, Southern California Edison, at the April 14, 2009, Joint Committee Workshop, California Energy Commission at:

http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[116] A recent study recently completed by the Government Accountability Office (GAO) describes the various challenges facing increased use of PHEVs, as well as elaborating on specific developments that would be necessary for PHEVs to be competitive. Government Accountability Office, *Plug-in Vehicles Offer Potential Benefits, but High Costs and Limited Information Could Hinder Integration into the Federal Fleet*, GAO-09-493, June 2009; available from http://www.gao.gov/new.items/d09493.pdf; Internet; accessed on August 1, 2009.

[117] Ibid.

[118] Ibid.

[119] Testimony of Chelsea Sexton, Lightning Rod Foundation, at the April 14, 2009, Joint Committee Workshop, California Energy Commission at http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[120] Ibid.

[121] Energy Information Administration website: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html

[122] Ohnsman, Alan and Kiyori Ueno, *Nissan Plans to Add Electric Vehicles to U.S. Factory*, Bloomberg.com

[123] The charging connector for plug-in electric vehicles completed Underwriters Laboratories (UL) certification testing during June 2009. *Underwriters Laboratories Approves SAE J1772 Charging Plug*, Sam Abuelsamid, AutoBlogGreen, June 28, 2009; available from http://www.autobloggreen.com/2009/06/28/underwriters-laboratories-approves-sae-j1772-charging-plug/; Internet; accessed on August 1, 2009.

[124]AEO 2009, Figure 8: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html

[125] EIA: http://www.eia.doe.gov/kids/energyfacts/sources/IntermediateHydrogen.html

[126] http://www.cafcp.org/sites/files/Action%20Plan%20FINAL.pdf

[127] http://www.hydrogencarsnow.com/chevy-equinox-fuel-cell-suv.htm and http://www.daimler.com/dccom/0-5-1200805-1-1201974-1-0-0-1201138-0-0-135-0-0-0-0-0-0-0.html

[128] Testimony of John Mough, California Department of Food and Agriculture, Division of Weights and Measures, at the April 14, 2009, Joint Integrated Energy Policy Report and Transportation Committee Workshop.

[129] Testimony of Michael Coates, Mightycomm, on behalf of Daimler AG, at the April 14, 2009, Joint Integrated Energy Policy Report and Transportation Committee Workshop.

[130] The California State Offshore area includes all submerged lands within 3 miles of the state boundary. Federal Outer Continental Shelf (OCS) waters extend from this 3-mile California offshore boundary line to a 200-mile limit from the California state land boundary. More details concerning these limits and other OCS boundaries can be obtained at the following link: http://www.mms.gov/ooc/newweb/QandA.htm

[131] As of July 2009, the Big West refinery in Bakersfield is temporarily idled as a consequence of the Chapter 11 filing and subsequent business decisions of the parent company, Flying J. It is assumed that this facility will be purchased by another company and resume operations no later than January 2011.

[132] California is one of the seven states contained in the western geographic subsection of the United States that comprise Petroleum Administration for Defense District V or PAD District V. The EIA revised Reference Case forecast shows refinery distillation capacity growing at an average rate of 0.47 percent per year between 2008 and 2030 for PAD District V. AEO 2009 revised Reference Case, Table 102, April 2009. A link to the table is as follows: http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/arra/excel/sup_ogc.xls

[133] Over the last three years (2006 through 2008), the portion of crude oil waterborne receipts into California that have been imported through marine terminals in Southern California has averaged 59.1 percent of the total waterborne crude oil imports to the state.

[134] Additional information concerning marine vessel tanker definitions and sizes can be obtained by reviewing a presentation by Pacific Energy Partners at the following link: http://www.pacificenergypier400.com/pdfs/TANKERS/TankerBusEmissions.pdf

Another resource that includes descriptions and definitions for all types of marine tankers (both crude oil and petroleum products) can be viewed at the following link: http://www.globalsecurity.org/military/systems/ship/tanker-types.htm

[135] The crude oil import facility proposed by Pacific Energy Partners has a design capacity of 4 million barrels of crude oil storage and a daily import capability of up to 250,000 barrels per day of crude oil. These storage capacities and throughput design equate to 1 million barrels of storage per 23 million barrels of imports per year. Additional project information is located at the following link: http://www.pacificenergypier400.com/index2.php?id=3

[136] *Survey of Available Data on OCS Resources and Identification of Data Gaps*, U.S. Department of Interior, Mineral Management Services, Report MMS 2009-015, May 2009, Appendix C, Table C-1, page C-2; available from http://www.doi.gov/ocs/report.pdf; Internet; accessed on August 2, 2009.

An historical assessment of crude oil reserves and production in the most active OCS region, the Gulf of Mexico, is contained in the following report: *Estimated Oil and Gas Reserves Gulf of Mexico, December 31, 2005*, U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, May 2009, Table 6, page 45; available from http://www.gomr.mms.gov/PDFs/2009/2009-022.pdf; Internet; accessed on August 2, 2009.

[137] Ibid, page 5.

[138] A link to EIA's assessment is as follows: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/ongr.html

[139] A link to the MMS press release is as follows: http://www.mms.gov/ooc/press/2008/pressDOI0730.htm

[140] A list and location of all of the offshore crude oil and natural gas production platforms in state and federal waters off the coast of California is described by the Mineral Management Services (MMS), a division of the Department of the Interior. A link to this information is as follows: http://www.mms.gov/omm/Pacific/offshore/platforms/platformintro.htm

[141] Energy Commission estimate based on information obtained from California State Lands Commission and County of Santa Barbara presentations. The CSLC staff estimate of Tranquillon Ridge production is more conservative than the one Aspen prepared on behalf of the County of Santa Barbara. CSLC estimate from the Commission Informational Hearing, Tranquillon Ridge Field, January 6, 2009. A link to the presentation is as follows: http://archives.slc.ca.gov/Meeting_Summaries/2009_Documents/01-06-09/ITEMS_AND_EXHIBITS/R01Exhibit.pdf

The Aspen estimate was obtained from Figure 2-3 of the Final EIR released on March 27, 2008. A link to the document is as follows:
http://www.countyofsb.org/energy/documents/projects/TranqRidgeFinalEIR/index.htm

ENERGY COMMISSION staff analysis of these two information resources has derived estimated incremental cumulative crude oil production from Tranquillon Ridge of between 60 and 110 million barrels for the first 12 years of the project.

[142] On July 24, 2009, the California state Assembly defeated by a vote of 43-28 an agreement that had been approved by the state Senate to permit Plains All American to proceed with their Tranquillon Ridge Project. *California's Expanded Drilling Plan Delayed But Not Dead*, Cassandra Sweet, Dow Jones Newswires, July 28, 2009, reprinted by Rigzone; available from http://www.rigzone.com/news/article.asp?a_id=78651;

Internet; accessed on August 2, 2009. The Assembly later undertook an unusual move to vote in favor of expunging the roll-call votes on AB 23 for removing the identity of Assembly members who voted for, against, or did not cast a vote on this measure. However, a full accounting of the official roll-call is available from other sources. See: *Erase the Cowardice*, San Francisco Chronicle, Editorial, August 3, 2009; available from http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2009/08/03/ED7E192A9L.DTL#ixzz0N7rq0uAZ; Internet; accessed on August 3, 2009.

[143] California gasoline demand has continuously declined since peaking in 2004 at 15.91 billion gallons. During the first four months of 2009, gasoline demand is down 2.1 percent compared to the same period in 2008. If gasoline demand in 2009 turns out to be lower than 2008, the five years of consecutive decline in demand is something that has never happened since the end of World War II. The only other period of four consecutive years of declining gasoline demand was between 1978 and 1982.

[144] In 2007, demand for transportation fuels was 22.91 billion gallons (15.66 billion for gasoline, 3.81 billion for diesel fuel, and 3.45 billion for jet fuel). Total demand for these three fuels had declined to 21.50 billion gallons in 2008 (14.92 billion gallons for gasoline, 3.43 billion for diesel fuel, and 3.15 billion for jet fuel).

[145] As of July 2009, the Big West refinery in Bakersfield is temporarily idled as a consequence of the Chapter 11 filing and subsequent business decisions of the parent company, Flying J. It is assumed that this facility will be purchased by another company and resume operations no later than January 2011.

[146] California is one of the seven states contained in the western geographic subsection of the United States that comprise Petroleum Administration for Defense District V or PAD District V. The EIA revised Reference Case forecast shows refinery distillation capacity growing at an average rate of 0.47 percent per year between 2008 and 2030 for PAD District V. AEO 2009 revised Reference Case, Table 102, April 2009. A link to the table is as follows:
http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/arra/excel/sup_ogc.xls

[147] The forecast of revenue passenger enplanements (boarding of aircraft by paying passengers) by FAA for individual states was used as a starting point. Average fuel use per enplaned passenger was then calculated for historical periods. Future fuel use per enplaned passenger was then adjusted over the forecast period to reflect improvements in fuel economy. *FAA Aerospace Forecast Fiscal Years 2009–2025*, Federal aviation Administration (FAA), April 2009; available from
http://www.faa.gov/data_research/aviation/aerospace_forecasts/2009-2025/media/2009%20Forecast%20Doc.pdf; Internet; accessed on August 9, 2009.

The data used to assess improvements in fuel economy were obtained from Table 22 of this publication. A link to Tables 1 through 22 is available from
http://www.faa.gov/data_research/aviation/aerospace_forecasts/2009-2025/media/Web%20Air%20Carrier%202009.xls; Internet; accessed on August 9, 2009.

[148] This region of the United States includes the states of Arizona and Nevada. A map of all of the states in this specific census region is available from http://www.eia.doe.gov/oiaf/aeo/supplement/supmap.pdf; Internet: accessed on August 9, 2009.

[149] *Supplemental Tables to the Annual Energy Outlook 2009, Updated Reference Case with ARRA*, Energy Information Administration, April 2009, Table 8 available from
http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/arra/excel/suptab_8.xls; Internet; accessed on August 9, 2009.

[150] *Supplemental Tables to the Annual Energy Outlook 2009, Low Oil Price Case*, Energy Information Administration, March 2009, Table 8 available from
http://www.eia.doe.gov/oiaf/aeo/supplement/lp/excel/suptab_8.xls; Internet; accessed on August 9, 2009.

[151] Kinder Morgan has already approved an expansion of the CalNev system between Colton and Las Vegas from 158 thousand barrels per day (TBD) to 200 TBD. Due to the recent downturn in demand and reduced forecasts over the near and mid-term periods, the company has decided to push off commencement of construction to a later date. *Kinder Morgan/SFPP, L.P. Pipeline System*, Ed Hahn, Kinder Morgan Energy Partners, L.P., April 14, 2009 presentation, slide 12 available from
http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/14-Hahn_Ed_Renewable_Fuels_and_Pipeline_Issues.pdf; Internet; accessed on August 10, 2009.

[152] The Holly Energy Partners project involves constructing a petroleum product pipeline from Salt Lake City, Utah to Las Vegas, Nevada. The pipeline would have an initial capacity of 62,000 barrels per day that could be operational by the end of 2010.

[153] *Chevron Energy and Hydrogen Renewal Project*, Draft Environmental Impact Report, State Clearinghouse No. 2005072117, City of Richmond Project No. 1101974, Volume 1, pp. 3-32 to 3-34 available from http://www.ci.richmond.ca.us/DocumentView.aspx?DID=2729; Internet; accessed on August 9, 2009.

[154] Ibid., page 1-1.

[155] Chevron Richmond Refinery Energy and Hydrogen Renewal Project, Chevron U.S.A., Inc. available from http://www.chevron.com/products/sitelets/richmond/renewal/; Internet; accessed on August 9, 2009.

[156] *Big West Supports Alternative D For the Clean Fuels Project*, Big West of California press release, September 19, 2008, page 2, available from http://www.bigwestca.com/bigwest/ShowDoc/BEA+Repository/bigwestPortal/bigwestDesktop/1_HomePage/news/news_8/pr8; Internet; accessed on August 9, 2009.

[157] *Flying J Files to Reorganize Under Chapter 11*, Flying J press release, December 22, 2008 available from http://www.flyingj.com/flyingjPortalWebProject/ShowDoc/BEA+Repository/flyingjPortal/flyingjDesktop/2_CompanyBook/3_PressPage/files/pr15/5; Internet; accessed on August 9, 2009.

[158] UNEV update from their web site available from http://www.unevpipeline.com/; Internet, accessed on August 9, 2009.

[159] All prices used in this work are in 2008 dollars, using the November 17, 2008, California Energy Commission deflator series from Moody's Economy.com unless specifically stated otherwise.

[160] The subset of premium light sweet oil constitutes a relatively small percentage of the oil actually refined in the United States or California, but prices for it are those most commonly referred to in the media.

[162] Scenario Analyses of California's Electricity System: Preliminary Results for the *2007 Integrated Energy Policy Report*, Appendix H-3; June 2007; Energy Commission-200-2007-010-SD-AP.

[163] From the February 10, 2009, Energy Commission staff workshop; can be found at http://www.energy.ca.gov/2009publications/CEC-600-2009-001/ENERGY COMMISSION-600-2009-001-SF.PDF.

[164] These growth rates are consistent with guidance and forecasts provided by the Demand Analysis Office of the Energy Commission.