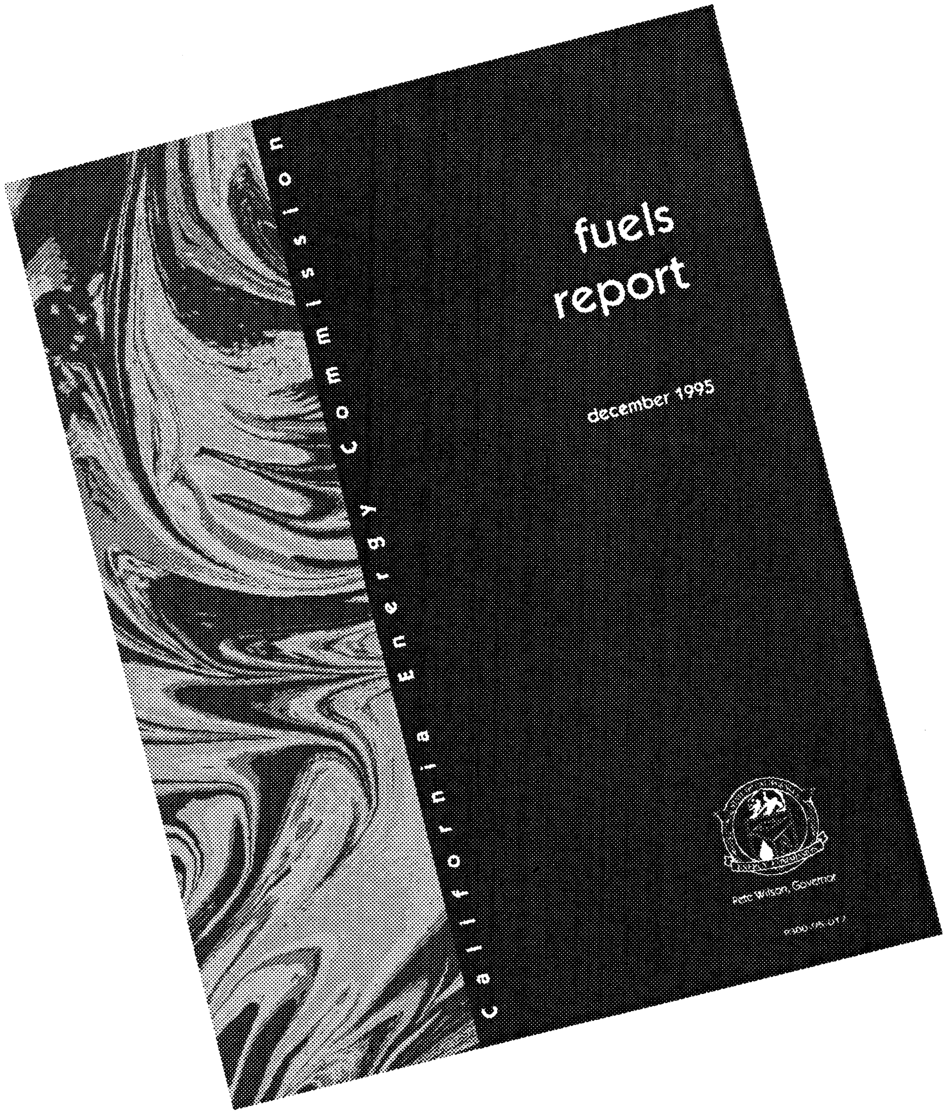

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The ***Fuels Report*** is prepared in response to legislative requirements specified in Public Resources Code Section 25310(a). The statute calls for the California Energy Commission to submit to the Governor and Legislature a comprehensive report describing emerging trends and long-range forecasts of the demand, supply and price of petroleum and petroleum products, natural gas, coal, and synthetic and other fuels. The report also must include specific recommendations for legislative or administrative actions needed to maintain sufficient, secure and affordable fuel supplies for the state.

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Tosco Refining Company
Transwestern Pipeline Company
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CHAPTER 6: CONTINGENCY PLANNING ISSUES

EXECUTIVE SUMMARY

WORLD OIL TRENDS

If world oil demand increases more rapidly than the expected growth in worldwide oil production, volatility in world oil prices could result, adversely affecting the California economy. World production is expected to continue increasing, consistent with increasing estimates of world oil reserves, with more countries producing oil and seeking foreign investment to develop indigenous oil resources. Currently, total world oil production is 66 million barrels a day, of which 40 percent is from the Organization of Petroleum Exporting Countries (OPEC) and 60 percent is nonOPEC. This ratio is a shift from the 1974 ratio of 53 percent OPEC and 47 nonOPEC, thus weakening OPEC's market share of world production.

NonOPEC oil production is currently increasing at a faster rate (70 percent of new production) than OPEC production, despite the decline in production from the United States and the former Soviet Union. This production ratio might not continue beyond the end of the decade because of the smaller size of known reserves in nonOPEC countries. At the present time, the largest known oil reserves are contained in OPEC countries.

The long-term demand forecasts of the International Energy Agency (IEA) suggest that world oil demand will increase an average of 1.8 percent annually to 2010. The most significant growth in world oil demand is expected to come primarily from Asian countries. Conventional thinking assumes that increases in production will keep pace with modest increases in demand. The alternative demand scenario, however, is much more uncertain, with the potential for a very rapid demand increase, particularly in China, which exceeds the current rate of production. If demand grows faster than production capacity, oil supply markets will tighten, driving up prices worldwide.

Some forecasters believe oil prices may increase considerably from the present rate of $18 per barrel to $30 per barrel, or higher, by 2005. This potential increase may be the result of: 1) oil demand increasing more rapidly than expected, 2) OPEC's market share increasing substantially, and 3) nonOPEC reserves dwindling. Other forecasters expect production to be adequate and long-term prices to range between $15 and $20 per barrel. History has shown that oil prices have been volatile as a result of a variety of geo-political events, especially those that occur in critical oil producing countries. This volatility is expected to continue, changing the short-term supply and price outlook overnight. Due to the importance of transportation in California, and the transportation sector's dependence on oil, the resulting price shocks could seriously affect the state's overall economy.

✓ The Energy Commission will continue to encourage the conservation and diversification of energy resources as a prudent approach for California, to mitigate the potential economic consequences of higher oil prices in the future.

CALIFORNIA OIL SUPPLIES AND REFINED PRODUCTS

Declining domestic oil production, in Alaska as well as California, will result in greater California dependency on foreign oil imports from both OPEC and nonOPEC suppliers. Future California oil production, although uncertain, is expected to decline an average of 2 percent to 3 percent per year during the next 20 years. California's thermally enhanced oil recovery is currently responsible for 63 percent of California's onshore production, but the extent of its use will continue to be sensitive to future oil price paths. More dramatic than the decrease in California production, Alaska oil production is forecast to decline 12 percent per year during the same time period.

The major challenge facing the California oil refining industry during the next decade is not so much the availability of crude oil, but rather the availability of in-state refining capacity to produce sufficient volumes of California-specific reformulated gasoline and diesel. Closure of two small refineries in 1995 brings the total refinery closures in California to 20 since 1982, reducing distillation capacity by 23 percent. To date, the refining industry has compensated for the loss of capacity by increasing utilization rates from about 70 percent in 1982 to 95 percent in 1993, resulting in total output increases. This leaves a limited ability to increase the product output on a sustained basis. Based on current information available from oil companies, California refineries have the ability to meet the demand for Phase 2 RFG in 1996, even under a high demand scenario. If California continues to lose refining capacity over the next decade and demand for refined products remains level or increases, then refiners have the option to either import additional volumes of finished products, import additional refined product blendstocks, or perform refinery modifications (such as debottlenecking).

In the short term, a major unscheduled outage may cause a temporary tight supply situation because of the high utilization rate. However, there are several options available which may help refiners to mitigate the tight supply. First, existing inventories of product and blendstock may be drawn down to meet demand. This option has been made more viable by increased storage capacity in the state as a whole. Second, refiners may seek a California Air Resources Board (CARB) variance to offset the volume of fuel lost by the outage. Third, additional refined products or blendstocks may be imported.

In addition, the Energy Commission is working closely with CARB through the Reformulated Gasoline Assessment Center in order to maintain a high level of readiness to respond quickly and cooperatively to any event which has the potential to cause an interruption in the supply and availability of Phase 2 RFG.

The declining refining capacity in California, along with new federal and state regulations, have also impacted wholesale and retail marketing in California. Especially with the transition to Phase 2 reformulated gasoline (RFG) in 1996, petroleum marketers will face new challenges and changes in the way they do business in California.

✓ The Energy Commission will analyze statewide refinery capacity, output and the supply/demand balance within California to evaluate whether adequate supplies of reformulated gasoline are available during the 1996 transition and beyond.

✓ The Energy Commission should study the potential impacts of different world oil price paths and various levels of oil imports on California's economy.

REFORMULATED FUELS

The need for cleaner air in California and the requirements of the federal Clean Air Act Amendments require CARB to develop cost effective methods of achieving air quality standards. Phase 2 of CARB's reformulated gasoline program requires production of RFG at the refineries by March 1, 1996, availability for sale at the wholesale level by April 15, 1996, and at the retail level by June 1, 1996. Although the transition to CARB Phase 2 RFG will create a gasoline formulation unique to California and pose certain challenges in the way the petroleum industry conducts day-to-day business, implementation of this program is an important step forward in the state's goal of achieving air quality standards.

To meet the fuel specifications for Phase 2 RFG, California refiners have spent more than four billion dollars for refinery upgrades and retrofits. Based on current information available from oil companies, California refineries have the ability to meet the demand for Phase 2 RFG in 1996, even under a high demand scenario. The refining and distribution of Phase 2 RFG pose challenges to the industry in meeting fuel specifications and providing segregated storage for additional product types.

CARB formed an RFG Advisory Committee to facilitate the introduction of CARB Phase 2 RFG in California by providing a forum for discussing issues and concerns with all parties affected by the production, distribution, and use of RFG. The Energy Commission is working closely with CARB to help pave the way for a smooth transition to CARB RFG. It is the shared goal of both agencies to evaluate the petroleum industry's ability to provide Phase 2 RFG to meet the needs of California's motorists.

✓ The Energy Commission will continue to participate in the RFG Advisory Committee with CARB and report on the petroleum industry's ability to provide Phase 2 RFG to meet the needs of California motorists.

✓ The Energy Commission is providing the expertise for timely and accurate assessment to decision makers of potential impacts to the supply and distribution of Phase 2 RFG during the transition period.

✓ The Energy Commission will monitor fuel deliveries to pipeline terminals and provide credible and accurate information on the potential for regional spot shortages.

ALTERNATIVE FUELS AND VEHICLES

The technology for alternative fuel vehicles has developed gradually due to a variety of market and regulatory uncertainties and the competition from plentiful and low priced petroleum fuels. The alternative fuels currently in use in California include M85 (85 percent methanol, 15 percent gasoline), compressed natural gas, propane and electricity.

The availability and use of alternative fuels is expected to increase gradually, potentially to one million vehicles by 2005. The incentive for this increase will be largely in response to regulations for low-emission vehicles. While the overall supply of alternative fuels is not expected to be a significant constraint, the availability of an adequate network of refueling sites may remain a constraint. Forecasts of comparative prices for alternative fuels could change significantly if federal and state excise tax rates are restructured.

✓ The Energy Commission should consider alternative fuel incentive policies in light of the potential for petroleum fuel price shocks.

NATURAL GAS

Over the past decade, the natural gas market has become increasingly competitive in response to regulatory reforms at the state and federal levels. At the wellhead, natural gas production has been completely deregulated. Given the partially monopolistic nature of gas transmission network which delivers gas from the producer to the end-use customer, regulators still oversee transportation and distribution services offered by pipeline companies and utilities. The use of incentive ratemaking by the CPUC, the implementation of capacity release programs at the federal level, and the development of gas market centers throughout the United States and Canada have allowed regulators to promote market competition in a regulatory environment.

With market competition growing and a push towards more environmentally-acceptable fuels, the outlook for the use of natural gas in California is better than ever. An abundant supply of natural gas is available to California from within the state, as well as from Canada, the Southwest United States, and the Rocky Mountains. During the 20-year forecast horizon, Canadian and Rocky Mountain supplies to California will increase while Southwest gas will slowly relinquish its role as the dominant gas supplier to the state. Natural gas demand in the state will grow 1.2 percent per year. California end-use price changes during the forecast period will range from a 0.1 percent decrease to a 2.7 percent increase annually, depending on the customer sector and the utility service territory.

Despite this optimism, the Energy Commission recognizes that the future direction of the natural gas market could vary considerably, depending on future regulatory action and market development. Among the largest uncertainties are: 1) electricity industry restructuring, 2) expected growth in demand for natural gas in Mexico, 3) market penetration of natural gas vehicles, 4) emerging technologies that could potentially displace natural gas, and 5) refinements to the Federal Energy Regulatory Commission's capacity release program.

- ✓ The Energy Commission will continue to support policies which promote consumer access to the most competitive natural gas supplies.

- ✓ The Energy Commission encourages the development of a competitive natural gas pipeline transportation market in California to complement the benefits of the capacity release program at the federal level.

- ✓ The Energy Commission will further refine the North American Regional Gas Model, especially focusing on analysis of the natural gas resource base in North America to ensure accurate long-term gas supply and price forecasts.

CONTINGENCY PLANNING

The Energy Commission maintains an operational and flexible energy shortage response plan, designed to work in any emergency. The plan represents a dynamic planning process to evaluate, define and respond adequately to natural disasters and man-made events alike. The Energy Commission works cooperatively with the Governor's Office of Emergency Services as well as other state, federal and local agencies, as part of the state's emergency response effort.

Since one of the functions of the Energy Commission is to ensure the adequate supply of energy for public health, safety and welfare, the plan includes a Petroleum Fuels Set-Aside Program which is used to obtain fuel for emergency responders and essential service providers who are unable to obtain sufficient supplies. The program was used in the Energy Commission's response to the Northridge earthquake on January 17, 1994, and the distribution problems associated with the introduction of reformulated diesel fuel in California beginning October 1, 1993.

The Energy Commission has also assisted local jurisdictions in improving their energy shortage preparedness through a Local Government Assistance Program. The Energy Commission developed a handbook for local emergency planners and awarded more than $1 million in grants to 14 different local jurisdictions for the development of their own energy shortage response plan.

- ✓ The Energy Commission will maintain its high level of readiness to respond quickly and cooperatively to any event which has the potential to cause an energy supply disruption.

Chapter 1
WORLD OIL TRENDS

INTRODUCTION

In considering the outlook for California's petroleum supplies, it is important to give attention to expectations of what the world oil market may look like over the next 20 years since the world market influences California's petroleum market. Will world oil demand increase and, if so, by how much? How will world oil prices be affected? Will the future production capacity of oil producing countries be adequate to meet demand? Will OPEC regain market share and greater control over prices? All of these variables affect what California consumers pay for gasoline, diesel and other petroleum products.

This chapter provides an overview of world oil trends and events and discusses some of the long term forecasts of world oil supply, demand and price. It concludes with a discussion of uncertainty in long-term forecasts and why energy diversity is an important policy to pursue even during times of apparent energy abundance.

NEAR TERM

The competition between OPEC and nonOPEC producers continued through 1994. NonOPEC production continued to rise in 1994, weakening OPEC's market share of world production. World oil production, including natural gas liquids, increased by slightly over 1 percent in 1994 to approximately 66 million barrels per day. NonOPEC countries comprised almost 60 percent of this total. The International Energy Agency (IEA) expects nonOPEC production to increase further in 1995 by approximately 600 thousand barrels per day.[1] Others expect nonOPEC production to continue to represent most of the increase in world oil production through the rest of this decade.[2]

Production from two nonOPEC countries, however, continued to decline in 1994. Former Soviet Union production dropped by nearly 10 percent. Major discoveries have been made at Tengiz, in Kazakhstan, but unresolved agreements on export routes have limited development. Petroleum production in the United States, including natural gas liquids, dropped 2 percent in 1994 to approximately 8.5 million barrels per day, a record low. Production in the United States has decreased continually since 1985. Foreign imports now represent about half of petroleum supplies to the United States.

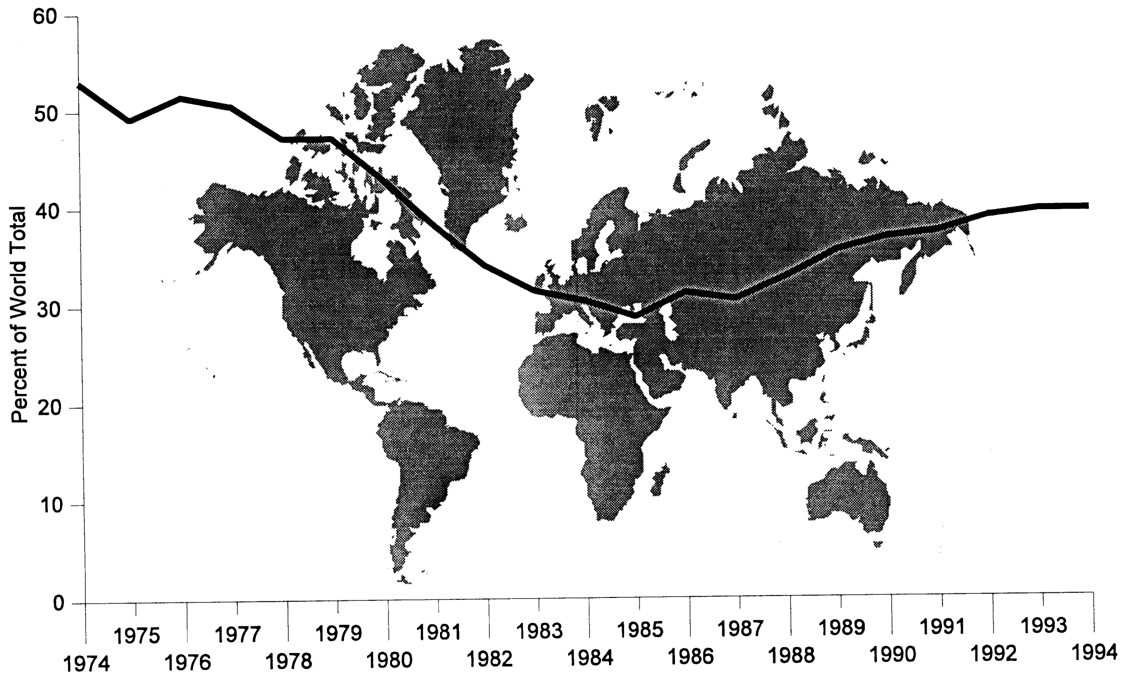
OPEC petroleum production also increased in 1994. Total OPEC production increased by nearly 1 percent. Venezuela and Kuwait accounted for most of the increase, adding nearly 300 thousand barrels per day. Most remaining member countries either decreased output or held their production stable. Iraq remains banned from selling oil on the world market, but some analysts expect that the country, when permitted, could immediately begin producing 2 million barrels per day with a longer term sustained output of over 3 million barrels per day. Prior to the Gulf War, Iraq was producing approximately 2.8 million barrels per day.

There is no consensus on the price effects of an Iraqi return to the world market. Some forecasts indicate

Figure 1-1

World Crude Oil Production

OPEC Share



that Iraqi production could be easily absorbed by increased demand in developing countries with little impact on world oil prices. Others expect additional downward pressure on prices over the next several years once Iraq production returns to the market.

Despite disagreements between oil producing and consuming countries on fuel taxes and oil revenue needs, the world oil market is now characterized by fewer countries trying to control or set oil prices and more countries encouraging foreign investment in developing indigenous resources. More partnerships are being formed between nations. Some countries, like Argentina and Venezuela, are actively privatizing oil field development. These conditions will likely produce further production gains as countries offer foreign investors more favorable terms. The overriding trend, however, is that oil development agreements are flourishing around the world.

LONG TERM

As shown in Figure 1-1, OPEC's share of world crude oil production has rebounded from the lows of the mid 1980s and leveled off at approximately 40 percent over the last couple of years.[3] Their proven oil reserves are, however, quite large, with estimates ranging from approximately 66 percent to 77 percent of the world's total. Although OPEC is currently finding it difficult to influence world oil prices, many longer term forecasts show the world increasing dependence on OPEC resources and paying higher prices. The distribution of proven world oil reserves remains one of the more persuasive arguments for this conclusion.

Two forecasts that show increasing oil prices and increasing OPEC market share include the Canadian Energy Research Institute (CERI) and the International Energy Agency (IEA). The CERI reference case forecast assumes that both stagnant production from nonOPEC sources from 1997 to 2000 and strong demand growth allow for crude oil prices to increase.[4] In addition, OPEC production is forecast to increase from 26 million barrels per day in 1994 to 30.9 million barrels per day in 2000 and just over 40 million barrels per day in 2009.

The IEA's 1994 World Energy Outlook reference case scenario shows even stronger world demand growth for petroleum and higher prices than CERI's case. By 2010, world demand for crude oil could increase by 40 percent, or 1.8 percent per year. Oil demand in the industrialized countries of the Organization of Economic Cooperation and Development (OECD) is forecast to grow at 0.8 percent per year and 3.8 percent per year for the rest of the world.[5] The "rest of the world" designation includes China, Africa, East Asia, Latin America, South Asia and the Middle East. The price path assumed in this scenario is that real crude oil prices will rise gradually from about $17 in 1995 to $28 per barrel in 2005 and remain flat during the rest of the forecast period.

There are several important uncertainties in the IEA's reference case. One is that supplies from the former Soviet Union and Central and Eastern Europe, which are assumed to be small net exporters, could vary significantly. Another large uncertainty is how governments will respond to these anticipated world oil developments. In the IEA reference case, governments take no regulatory action to curtail demand. Several experts that testified before the Energy Commission criticized the IEA forecasts as overstating oil demand growth and OPEC influence. Long term prices in their view could be expected to range between $15 and $20 per barrel in 1995 dollars.

While oil prices are expected to remain relatively stable in the long term, oil demand in certain regions of the world is expected to show strong growth. Despite fuel costs that are three to four times greater than in the United States, Asian countries are expected to account for the most significant growth in world oil demand at 3 percent to 4 percent per year. This translates into 600,000 to 700,000 barrels per day per year. Testimony received indicates that the world oil market could readily supply this growth since world production capacity is also expanding.[6] Expectations are that for the next 10 years the increase in demand will be met by petroleum from the Middle East, West Africa, the North Sea and, to some extent, Vietnam.

Beyond 10 years, the Tarim Basin of China (about the size of Texas) may offer one of the world's last regions of Saudi Arabian size oil reserves.[7] Reserve estimates range from as little as a few billion barrels to as much as 240 billion barrels. This can be compared to China's current proven reserves of 24 billion barrels. Exploration and development costs are high and the desert environment is hostile with frequent sandstorms and shifting sand dunes over 500 feet high in some areas. Future production levels from the region remain uncertain.

Despite the expected growth in petroleum imports over the next decade by Asian countries, gasoline demand will likely be met by Asian refineries because governments stress refining self-sufficiency as an important goal. As a result, there is excess gasoline refining capacity from over-investing in refineries. It is possible that Japan, for example, may become a gasoline supplier to the West Coast within five years once the country drops regulations in 1996 that currently prohibit fuel exports to the United States.

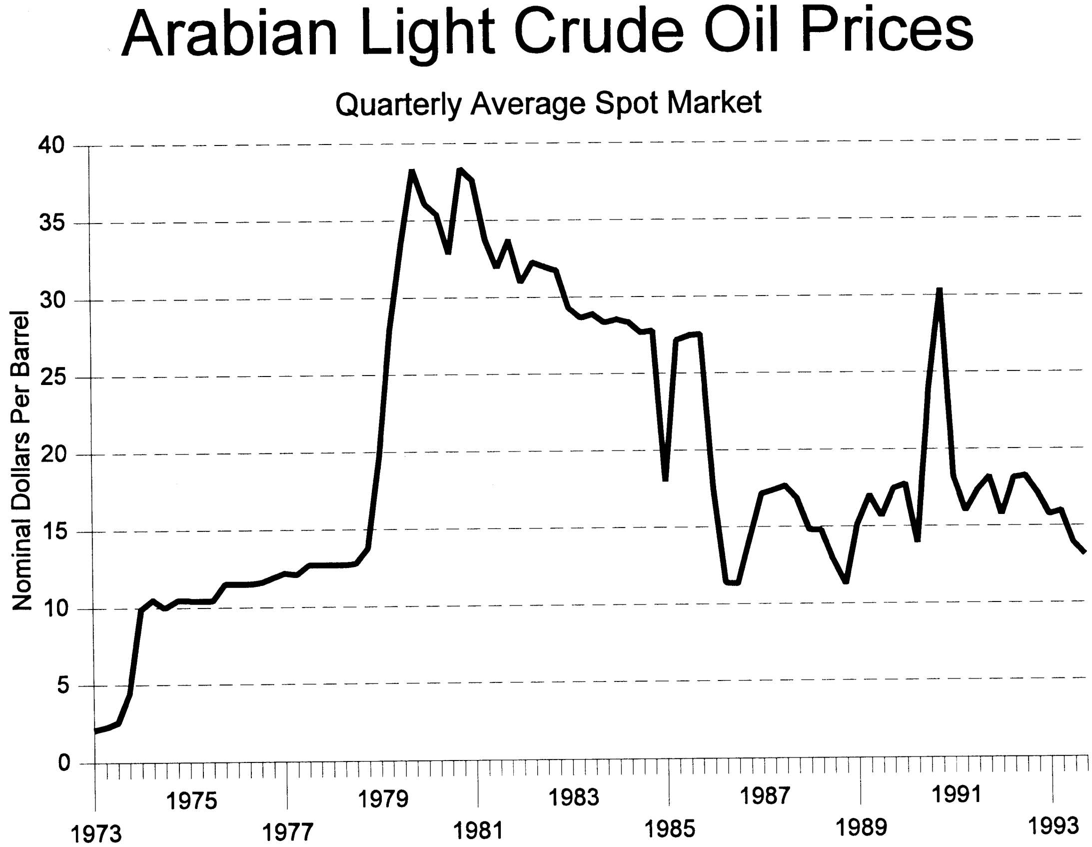
Diesel use in Asia, however, is expected to account for about half of the total product demand increase and refining capacity to produce high quality diesel is insufficient. California refiners who produce low sulfur diesel will have opportunities for sales to Pacific Rim countries.

In summary, many forecasters envision world oil demand increasing between 1 percent and 2 percent per year with more rapid growth in developing countries and slower growth in member countries of the OECD. Increasing foreign investment in oil development projects and privatization programs are expected to bring petroleum production gains. In the long term, the world will increasingly rely on the Middle East's immense oil reserves as demand in developing countries increases and supply from nonOPEC producers declines.

ENERGY FORECASTING AND UNCERTAINTY

The conventional view of the future world oil market is one of relatively stable or gradually increasing

Figure 1-2



world oil prices during the 20-year forecast period. Several current conditions support this judgment. Proven world oil reserves estimates continue to increase, exceeding 1 trillion barrels in 1995. OPEC nations continue to argue over production quotas and nonOPEC oil continues to defy any short term expectations of declining production. Oil prices remain low in inflation adjusted terms as do product prices. The world also has witnessed how increasing oil prices produce increased supplies from formerly marginal prospects and how price-induced conservation results in downward price pressure. These indicators can foster complacency toward energy and its critical importance to world economic activity.

Although oil supplies appear to be abundant, uncertainty always exists when attempting to predict future market conditions and oil prices. Historical trends clearly demonstrate oil price volatility as any petroleum fuel consumer during previous supply disruptions can confirm (see Figure 1-2).[8] Political events in major oil producing countries can still change the short-term supply and price outlook overnight. Even though stability characterizes oil prices today, it is sensible to expect that events yet to come will maintain the volatility of oil prices. It follows that the greater the dependence on oil during volatile price conditions, the greater the potential damage to economic activity. Cumulative losses to the United States (U.S.) economy from the price shocks of the past 20 years are estimated in the trillions of dollars.[9]

In a study completed in June 1995 for the U.S. Department of Energy, the Task Force on Strategic Energy Research and Development found that several conditions may lead to an erosion of national security and possible future supply disruptions.[10] Although the study emphasizes the value of energy research and development, the findings apply equally well to conditions which could collectively produce future oil price increases. The list includes:

- A reduction of world excess oil production capacity
- Expanding world oil demand
- Declining United States production
- Growth in supply of oil from the volatile Middle East and reserve concentration in this region
- A world still full of risks

While future short-term supply disruptions will continue to prompt price shocks, future demand also could produce steeper price increases in the long term than currently expected. Participants in the Energy Commission's oil price surveys have weighted many factors which could contribute to more aggressive future oil price increases. In the most recent survey, the predominant factor is strong demand growth from developing nations. Most of the growth in world oil demand is expected to come from Asian countries. The rate of growth and the degree to which demand will be met with indigenous oil resources are, however, large uncertainties.

Countries such as China and India continue to experience significant economic growth. This change in the gross domestic product is not only associated with an overall increase in the demand for oil but also an increase in the per capita consumption of oil. Since these two countries possess over 2 billion people, even modest increases by world standards in their per capita oil consumption rates may have a significant impact upon world oil demand and prices. In 1992, China and India crude oil demand averaged approximately 0.7 barrels per person, compared to the United States average of 22.5 barrels per person and a world average of four barrels per person. If their combined average were to triple to 2.1 barrels per capita (similar to Thailand), world oil demand would increase by approximately 7 million barrels per day (11 percent of 1992 world production). Since this increase may occur gradually, the demand would likely be met by additional OPEC production.

China is the third largest energy consuming country in the world and its economy has grown over 9 percent per year since the 1980s.[11] While China relies on coal for over 75 percent of its energy requirements, the share of total demand met by coal is expected to decline dramatically from 68 percent in 1991 to 55 percent by 2010. At the same time, petroleum demand is expected to increase over 5 percent per year and represent 26 percent of total energy demand by 2010 from 17 percent in 1991.[12]

Transportation fuel demand in China is low at present, but the potential for growth as their economy and personal incomes grow is very large. The IEA estimates that road transportation energy demand will increase 7 percent per year between 1995 and 2010, even though roads are now relatively few in number and in poor condition. The poor condition of the existing transportation infrastructure has not curtailed popular interest in driving vehicles. A recent news account indicates that learning to drive in China is a popular and costly endeavor. Although thousands of driving students are paying more than a year in wages to learn to drive, they would need to spend over 30 years worth of wages to purchase an average priced vehicle in that country. Despite this high cost of vehicle ownership, the number of cars in China increased from 150,000 in 1979 to 1.4 million in 1995.[13]

On the supply side, China's petroleum production is expected to grow slowly through the 1990s increasing from about 3 million to 4 million barrels per day from 1995 to 2010. Most of this increase is assumed to originate from the Tarim Basin. If exploration of the basin is more successful, another 1 million barrels per day could be added to the production total, leaving imports to provide about 2 million barrels per day of supply. As previously noted, the Tarim Basin is viewed as a region of enormous oil development opportunity. Since work is just starting in that region, however, it is not known whether production will be high or low. If production does not meet expectations, then the country will rely more heavily on foreign imports. This could tighten world supplies and result in higher prices.

As with Iraq's eventual return to the world oil market, there is no clear consensus on the future world price of petroleum. Scenarios can be constructed which show declining world oil prices or more rapidly increasing prices. Dealing with these uncertainties means preparing for the possibility of higher priced oil in the future, even if the risk is perceived as small. It would be short sighted to do otherwise. The consequences of being unprepared can be extremely costly. From an energy policy perspective, conserving and diversifying energy resources remains a prudent approach for California and the nation to mitigate the economic damage that higher oil prices can bring. It is one way of investing in insurance against the possibility of future adverse world oil events. Chapter 4 discusses fuel diversity at greater length and its progress in California.

ENDNOTES

1. Petroleum Economist, February 1995, p. 6.

2. Testimony of Edward Krapels, Energy Security Analysis, 1995 Fuels Report Hearing, May 11, 1995.

3. Petroleum Economist, March 1995, p. 48.

4. Canadian Energy Research Institute, ***Taxing the Difference, World Oil Market Projections, 1994-2009***, Study No. 59, August 1994.

5. Member countries of the OECD include: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, Luxembourg, Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States.

6. Testimony of Edward Krapels, Energy Security Analysis, 1995 Fuels Report Hearing, May 11, 1995.

7. Ibid.

8. PennWell Publishing Company, ***Energy Statistics Sourcebook***, Ninth Edition, August 1994.

9. U.S. Department of Energy, ***Energy R&D: Shaping Our Nation's Future in a Competitive World, Final Report of the Task Force on Strategic Energy Research and Development***, June 1995, p. IX.

10. Secretary of Energy Advisory Board, U.S. Department of Energy, ***Energy R&D: Shaping our Nation's Future in a Competitive World***, June 1995.

11. International Energy Agency, ***World Energy Outlook***, 1994 Edition, p. 165.

12. Ibid., p. 170.

13. San Francisco Chronicle, "In Land of Few Cars, Learning to Drive Becomes All the Rage," July 28, 1995.

Chapter 2

CALIFORNIA PETROLEUM SUPPLY, TRANSPORTATION, REFINING AND MARKETING TRENDS

INTRODUCTION

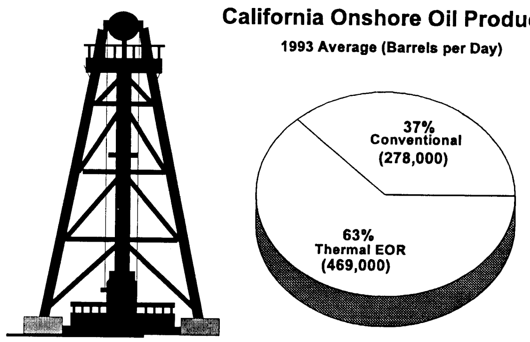
California is an integral part of the world oil market as a world-scale petroleum consumer. Historically, about 50 percent of this petroleum came from in-state production, 45 percent from Alaska and 5 percent from foreign sources. This chapter discusses how these petroleum supply sources will change over the next 20 years. The percentage supplied from foreign sources will increase as both Alaska and California production decline. This will occur despite expectations of level petroleum fuel demand in California's transportation sector over the next 20 years (as discussed in Chapter 4). These findings are based on gradual increases in oil prices. It should be noted that more abrupt increases in oil prices would cost consumers more but also stimulate additional production and add to California's current proven reserves of 4 billion barrels.

This chapter also includes an overview of California's petroleum transportation system and discusses issues pertaining to California's refining and marketing sectors. Refining sector trends show cause for concern. Fewer refineries are now located in California and utilization rates are high. If this trend continues, product availability could become limited and prices would increase. The market would respond by importing more petroleum products to California, but time delays can be expected. This is because refiners outside California have not invested in producing California-specific fuel and shipments from the Gulf Coast or other regions require time.

ONSHORE OIL PRODUCTION

Onshore California oil is currently recovered by both conventional and enhanced extraction techniques. Conventional methods use the natural pressure of an oil field or, if the pressure is too low, water is injected to increase the pressure of the oil field to allow greater amounts of oil to be removed. Enhanced oil recovery uses more advanced techniques to extract oil from fields that have been nearly depleted using conventional methods.

Figure 2-1
California Onshore Oil Production
1993 Average (Barrels per Day)



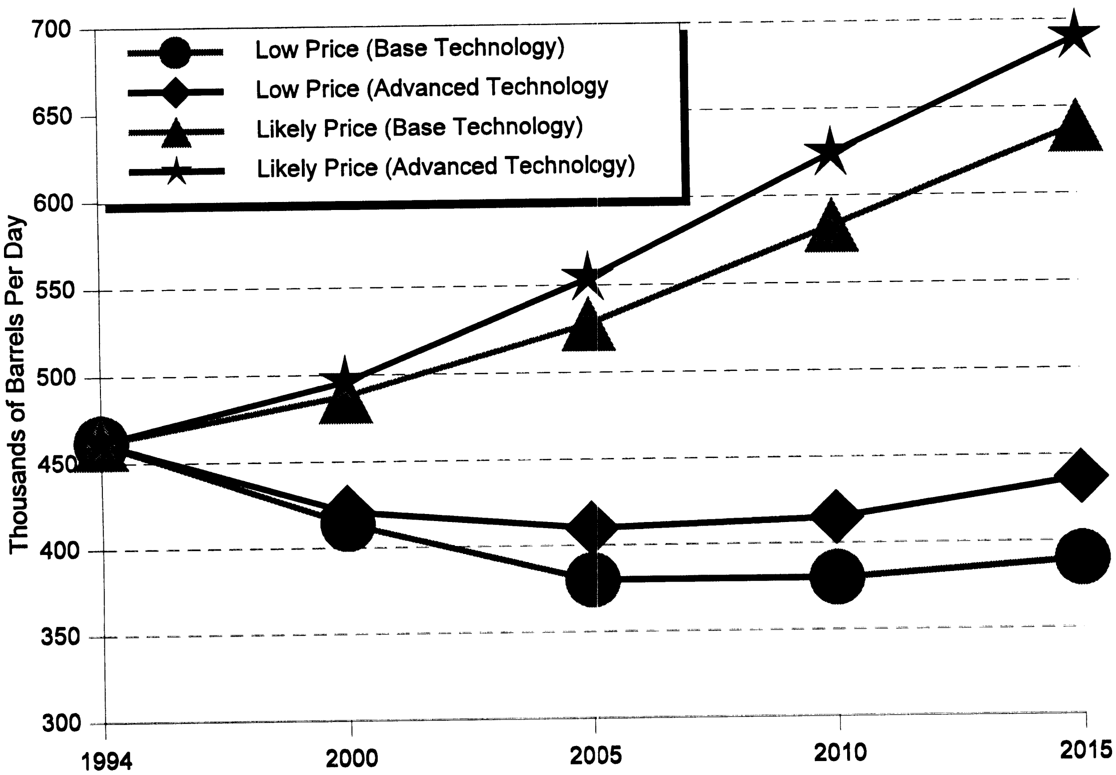
The principle of enhanced oil recovery is to inject some agent into the partially depleted underground oil reservoir to economically recover additional barrels of oil, which could no longer be obtained through traditional oil recovery methods. Carbon dioxide gas, hydrocarbon solutions, chemical polymers, and steam are types of agents injected into the reservoir. Steam injection, referred to as Thermally Enhanced Oil Recovery (TEOR), is important to California's total production since it represents about 63 percent of onshore production and is responsive to prevailing oil prices and technology advances (see Figure 2-1).[1] Furthermore, California TEOR production accounts for over 60 percent of total enhanced oil recovery production in the United States.

Onshore oil production has been declining since 1985 at an average annual rate of 3.4 percent.[2] In 1993, California onshore production averaged nearly 750,000 barrels per day or 79 percent of total California production. Statistical extrapolations from historical data produce a very broad range for California onshore production in the future. The range is so broad, varying between a 7.5 percent decline per year to a 1 percent increase per year, that it is not instructive to energy policymakers. To develop a more definitive forecast, the Energy Commission sponsored some modeling work to examine the effects of future oil prices on California's TEOR.[3]

The model used was the same as that developed for the Department of Energy analysis of lifting the Alaska North Slope (ANS) export ban. The low and most likely oil price paths from the Energy Commission's Delphi VII forecast were used and both "base and advanced" TEOR technology assumptions were considered. As shown in Figure 2-2, the results indicate that the TEOR production could represent

Figure 2-2

California TEOR Production



between 390,000 and 690,000 barrels per day by 2015.[4] Total onshore production in this case could then range between 433,000 barrels per day to 767,000 barrels per day by 2015. This assumes that TEOR production continues to represent an increasing proportion of total onshore production as shown by historical trends. At this growth rate, TEOR would represent about 90 percent of onshore production in 20 years, compared to 63 percent in 1993.

Based on initial responses to the current Delphi oil price survey, it appears unlikely that TEOR production could approach the upper range of 690,000 barrels per day shown by the modeling results. The current Delphi participants foresee still lower world oil prices than indicated in prior surveys. Furthermore, historical data on TEOR production has shown that production ranges between 400,000 and 500,000 barrels per day during periods of higher oil prices. This does not mean that California TEOR production could not meet or exceed the modeling result. As noted in Chapter 1, oil prices could follow a higher price path which would stimulate production while costing the consumer more.

If TEOR production follows the production path indicated by the low price, base or advanced technology modeling result, then TEOR production in 2015 becomes approximately 7 percent to 17 percent below 1993 production. Total onshore production would then range from 433,000 to 486,000 barrels per day by the end of the forecast period, about 35 percent to 42 percent less than 1993 onshore levels. This is equivalent to a 2 percent to 3 percent per year average decline. The Energy Commission believes this expectation is reasonable, but future oil prices could result in higher or lower production.

OFFSHORE OIL PRODUCTION

Offshore California oil is produced from fields that are located in both state and federal waters. State waters are those within three miles from shore and federal waters are those beyond three miles. Production from federal waters surpassed that of state waters in 1988 and now is nearly 2.5 times greater than state offshore production. Proven reserves in state waters are estimated at about 235 million barrels compared to 735 million barrels in federal waters.

Production in state waters has been declining since 1986. The September 1994 California ban on further offshore drilling in all state waters will lead to still fewer state resources contributing to the offshore total. Several platforms in the state waters of the Santa Barbara Channel are now being abandoned and removed because of uneconomical operating costs and reserve depletion.

Total long-term offshore oil production is expected to decline gradually. Proven reserves are near one billion barrels and the current production rate is about 200,000 barrels per day. A simple projection of historical trends indicates that production could decline an average of 0.2 to 4 percent per year reaching between 163,000 and 64,000 barrels per day by 2013.

This does not reflect short-term expectations for a further increase in federal offshore production. Short-term forecasts offered by the Minerals Management Service and the Division of Oil, Gas and Geothermal Resources indicate the addition of about 50,000 barrels per day in the 1995 to 1998 timeframe. The addition is from waters in the Santa Maria Basin and Santa Barbara Channel.

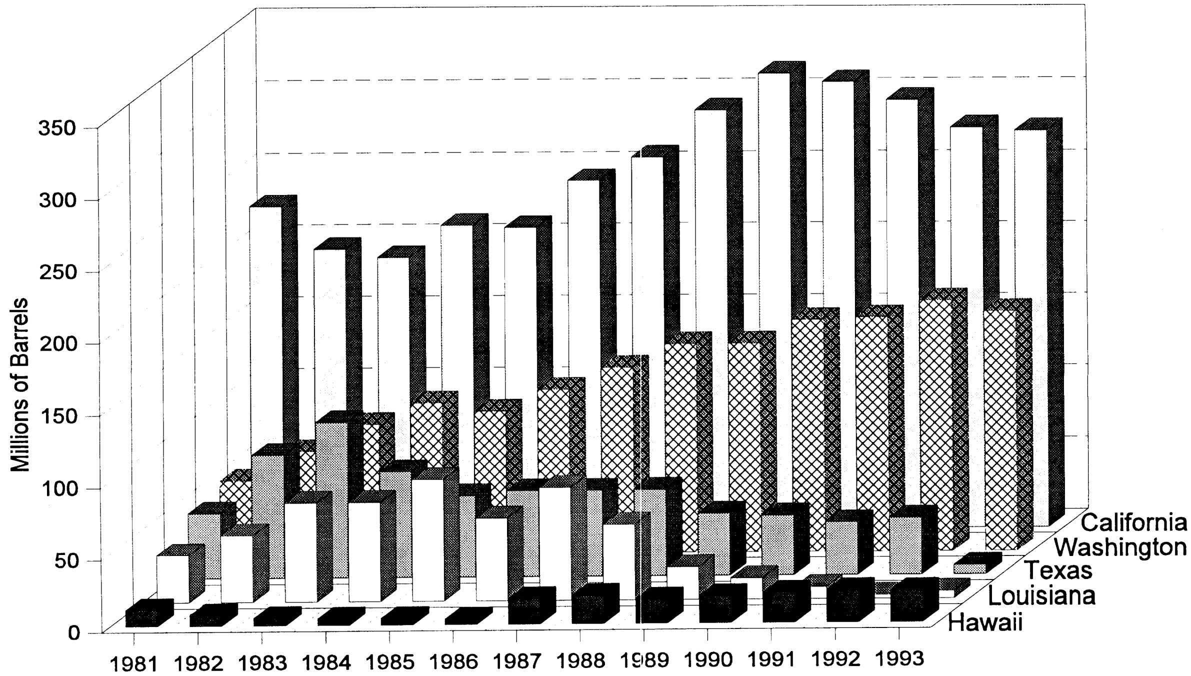
In the long term, offshore production will occur primarily within federal waters and could represent between 10 percent and 33 percent of total California production by the end of the forecast period compared to 21 percent in 1993. Combined with onshore oil production, total California oil production levels are expected to range between 497,000 and 649,000 barrels per day. This represents a 31 percent to 47 percent decline from 1993 production.

PETROLEUM SUPPLIES FROM ALASKA

Although Alaska supplies petroleum to refineries in many states (including Washington, Hawaii, Texas, and Louisiana), California is Alaska's largest customer. Figure 2-3 shows the distribution of Alaskan North Slope (ANS) crude oil for the top five importers since 1981.[5] Supplies to California and Washington generally increased until 1990. Since 1990, however, declining Alaska production has gradually resulted in reduced supplies to California. This trend is expected to continue, although

Figure 2-3

Refinery Receipts of Alaska Crude Oil



California will remain a major market for ANS oil. For example, in 1993, California received 43 percent of its crude oil demand from Alaska.

An extrapolation of this trend indicates California continuing to receive lesser volumes of ANS oil and Washington continuing to receive increasing ANS volumes. Future supply conditions, however, are complicated by other factors in addition to declining Alaska production. Refinery ownership patterns and the potential for ANS oil exports are two examples.

Total Alaska petroleum production has been declining an average of 4 percent per year since 1989. Prudhoe Bay and Kuparuk are the number one and two producing North Slope fields, respectively, accounting for about 85 percent of total North Slope production. Prudhoe Bay production started declining in 1988. Production from Kuparuk is expected to remain fairly stable for five more years before declining. Kuparuk production is approximately one-third that of Prudhoe Bay. Cook Inlet production peaked at 83 million barrels in 1970 and has now declined to 15.5 million barrels per year.

Forecasts of total Alaska production by the Alaska Department of Natural Resources (ADNR) show that over the next 20 years production will decline an average of 12 percent per year.[6] As production declines further, the economic limit of the Trans Alaska Pipeline becomes a major factor. Some estimates indicate that once production falls to between 200,000 and 400,000 barrels per day, the pipeline will no longer technically or economically function.[7] Furthermore, this would leave 500 million to 1 billion barrels of "lost" recoverable liquids in the ground.

One caveat to these forecasts is that they do not reflect the influence of changes in government policy. An end to the ANS export ban appears to be imminent.[8] The study completed by the U.S. Department of Energy in June 1994 on lifting the ANS oil export ban indicated that permitting ANS oil exports could increase Alaska production.[9] Depending on the oil price path and the type of tankers used for transport, Alaska production could increase by approximately 55,000 to 70,000 barrels per day by 2000. The study findings also stated that permitting ANS oil exports could add 200 million to 400 million barrels to Alaska's reserves, about the same as those of the Endicott or Point McIntyre fields. Reserves are added because more resources become economic to produce as oil prices increase.

These findings on potential production increases would change the steepness of the production decline curves, but not the direction. This is because the production gains are smaller than the losses. The estimated increase in Alaska production by the end of 2000 from repealing the export ban is about one-third the volume of the total production decline that occurred between 1992 and 1993.

If restrictions on ANS exports to foreign countries are lifted, ANS petroleum demand in the Pacific Rim market could affect the supply to California. If current restrictions for transporting ANS crude by U.S. flagships only are lifted, ANS producers would be interested in shipping oil to Pacific Rim nations since the transportation cost for shipping by foreign vessels will be lower. Pacific Rim nations would purchase ANS oil because they are interested in secure supplies, their refinery configurations are compatible with ANS oil and it offers an opportunity to reduce trade deficits. On the other hand, OPEC suppliers, now providing countries like Japan with the bulk of their supplies, may compete vigorously with ANS suppliers resulting in lower levels of ANS shipments.

Despite the complexity, it is clear from production forecasts that California will be receiving significantly fewer barrels of oil from Alaska within the next six years. If history is any indicator, West Coast demand for crude oil, whether met by Alaska or another supplier, will increase gradually in the future if refinery capacity is expanded above current levels. The ADNR forecast shows Alaska demand for petroleum increasing 1.5 percent per year between 1995 and 2010. Historical Energy Information Administration data shows that Washington and Oregon petroleum product demand is also increasing.[10] Finally, California petroleum product demand has increased an average of 1.8 percent per year on average since 1976. However, the Commission expects this growth rate to slow and eventually level off over the next 20 years.

The longer term questions become: 1) what sources of supply will be used to fill the void between declining Alaska production and California demand? and 2) what are the effects on California from the range of oil supply possibilities?

FOREIGN PETROLEUM SUPPLY SOURCES

California relies on foreign oil for about 5 percent of its total petroleum demand. OPEC sources account for 1.5 percent of total demand with Indonesia providing slightly over half of the OPEC supply. NonOPEC petroleum accounts for the balance with Mexico providing a small fraction of this total.

Indonesia once supplied over 8 percent of California's petroleum deliveries.[11] These imports, however, have slowly been replaced by nonOPEC imports. Indonesia is expected to play less and less a role in California's petroleum supplies, although some isolated shipments may occur if the arrangements are profitable. Indonesia may itself become a net crude oil importer in the next few years as their production and consumption trends cross.

In the longer term, California can expect greater reliance on both OPEC and nonOPEC petroleum suppliers. Venezuela is a possible source of OPEC supply because of shorter transport distances and continuing additions to the country's reserve base, now estimated at 150 billion barrels. In 1992, Venezuela crude oil imports represented 23 percent of the nonArab OPEC crude imported to California.[12] Saudi Arabia is another expected future supplier because of its reserve base and capability to expand longer term market share. Middle East suppliers have provided crude oil to California in the past and will likely do so again.

California will also look to nonOPEC suppliers for petroleum. A larger volume of imports may come from Mexico where proven oil reserves are over 100 billion barrels. Imports from Canada may also continue, but Canada has a reserve to production ratio similar to the United States and will also import more oil in the long term. Imports from some South American countries, such as Argentina, are possible. Argentina is pursuing privatization of oil field development which is expected to increase production from that country.

These foreign oil supply possibilities illustrate that there are many potential suppliers of crude oil and that many more arrangements with foreign suppliers will be reached by California's petroleum refiners in the future. Some California refiners will need to make those arrangements sooner than others, particularly refiners without the upgrading equipment needed to minimize residual fuel oil yields from refining heavy crude oil. Increasing reliance on world oil market supplies does not guarantee economic havoc for California, but the value of pursuing energy conservation and fuel diversity policies would again become evident should disruptions in those supplies occur.

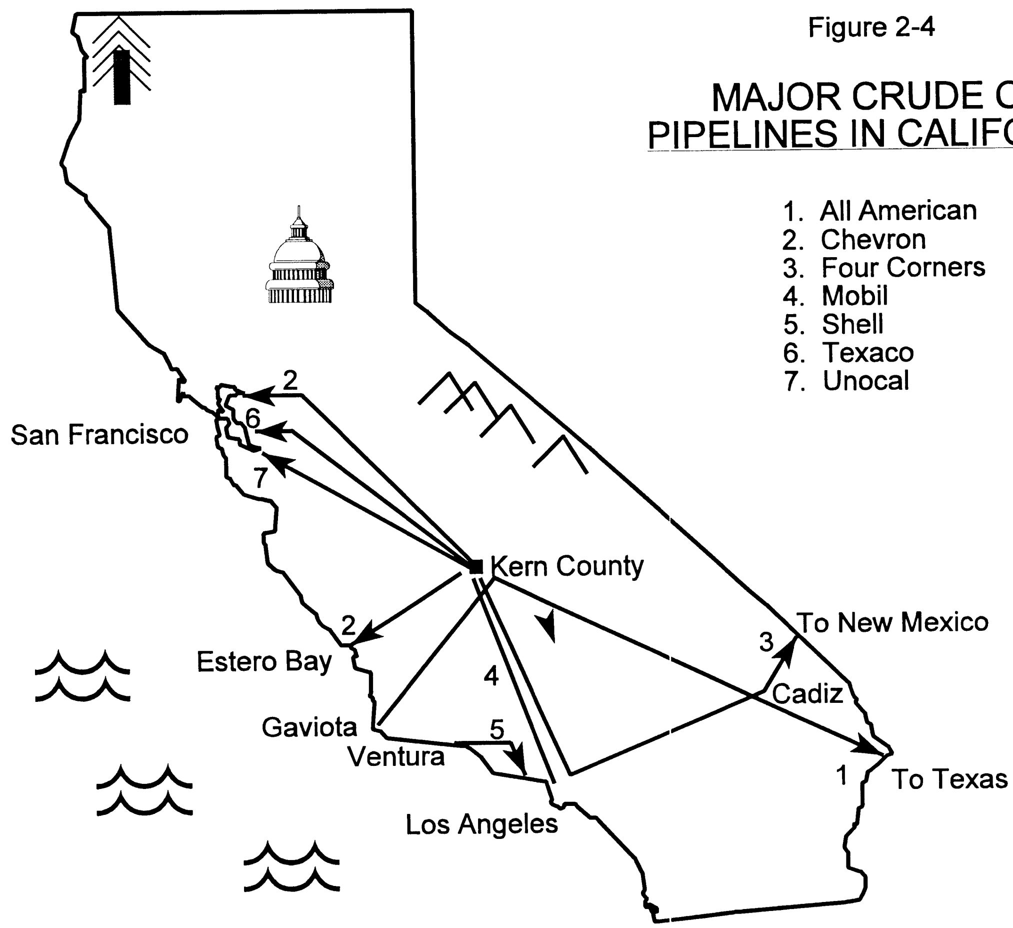
CRUDE OIL TRANSPORTATION

California relies on tankers from Alaska to deliver almost half of its petroleum supply, about 1 million barrels per day. Forty percent of this supply enters Northern California ports and 60 percent arrives in Southern California. The other half of California's petroleum supply is produced in-state and is primarily transported by pipeline to refineries in the San Francisco Bay area, the Los Angeles Basin and Bakersfield (see Figure 2-4). Pipelines are also used to bring offshore crude oil from state and federal

Figure 2-4

MAJOR CRUDE OIL PIPELINES IN CALIFORNIA

1. All American
2. Chevron
3. Four Corners
4. Mobil
5. Shell
6. Texaco
7. Unocal



waters onshore. Producers of both offshore and onshore oil also have the option of transporting their crude oil to the Gulf Coast via the All American pipeline, which has a maximum capacity of 300,000 barrels per day.

Crude oil from Kern County can be transported north to San Francisco by one of three pipelines owned respectively by Chevron, Texaco or Unocal. Kern crude oil can also be transported south to Los Angeles in either the Four Corners common carrier pipeline or Mobil's proprietary line. In addition, Chevron owns a pipeline going from Kern County west to Estero Bay where tankers then transport the crude oil to its refinery destination.

The Four Corners system from the San Joaquin Valley to Los Angeles (actually two parallel lines known as #1 and #63) has been operating at its capacity of 100,000 to 115,000 barrels a day.[13] This system has not been able to accommodate the total volume "nominated" by producers. When the volume nominated exceeds the pipeline capacity, all requests are prorated by a certain percentage. The Northridge earthquake on January 17, 1994, caused heavy damage to both the #1 and #63 lines, shutting down the system for nine days. Although the pipelines are currently operating, the damage has not been completely repaired and, consequently, the Four Corners pipeline continues to be over-nominated.

Part of the reason for the heavy demand on the Four Corners system is its use for transporting offshore oil from the Point Arguello field to Los Angeles refineries. Since there is no direct pipeline along the coast, producers of offshore oil use the All American Pipeline from Gaviota (just north of Santa Barbara) to its junction with Four Corners at Pentland. At this point, the heavy crude oil is blended with lighter San Joaquin Valley crude oil and transferred to the Los Angeles-bound pipeline. This blending procedure allows faster delivery rates. For environmental reasons, Santa Barbara County has required that offshore oil brought onshore at Gaviota must be transported by pipeline, not tanker.

Since the 1981 discovery of the Point Arguello field offshore Santa Barbara, several companies have proposed additional crude oil pipelines which could transport this oil from Gaviota to Los Angeles refineries. One proposal by Pacific Pipeline originally specified a route along the coast from Gaviota directly to Los Angeles. The current proposal would link with the All American pipeline in Kern County to Los Angeles, similar to the Four Corners route. The advantage of the new route is that it could transport up to 130,000 barrels per day of San Joaquin Valley crude oil as well as offshore crude oil to Los Angeles. This project continues to face opposition from local community groups and its construction remains uncertain.

Pipelines are also used to transport finished petroleum products from refineries to bulk terminals. Since California is a net exporter of finished petroleum products, pipelines are also used to deliver these products to terminals in Reno, Las Vegas and Phoenix. Chapter 3 discusses the anticipated concerns of transporting reformulated gasoline by pipeline.

CALIFORNIA'S DECLINING REFINING CAPACITY

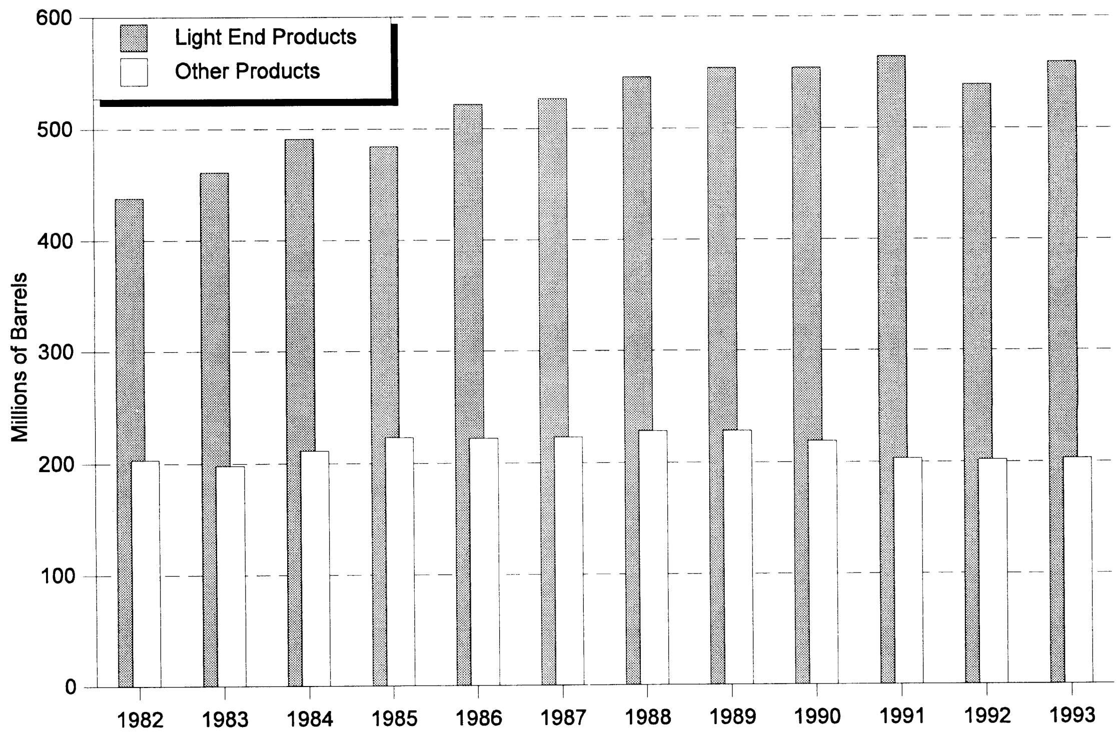
The major challenge facing the oil industry in California over the next decade will not be the availability of crude oil but the availability of refining capacity to make fuel to California's specifications, especially reformulated gasoline and diesel. Should any refinery experience an unscheduled outage, replacement supplies may be limited by a combination of factors: 1) fewer refineries in California and 2) the absence of refiners outside the state making the investments required to produce large quantities of reformulated fuels for the California market.

The refining industry in California has experienced a reduction in the number of operating refineries with a corresponding reduction in the statewide crude oil distillation capacity. Since 1982, the number of operating refineries in California has decreased from 44 to 24. This loss of 20 refineries represents a 23 percent loss in operable distillation capacity in the state, from 2.5 million to 1.9 million barrels per calendar day, a loss of 574 thousand barrels per calendar day.

Many of the refiners that ceased operation did so because they were unable to upgrade their facilities to produce the cleaner fuels, beginning with unleaded gasoline. Each refiner has had to decide whether or

Figure 2-5

California Refinery Output



not to make the substantial capital investment needed to meet CARB fuel specifications. Those refineries that cannot compete on a cost basis in California's clean fuel program may opt to close or to make fuel for markets outside the state.

This is the case for small independent refiners. Most have not been able to finance the investments to upgrade their facilities out of cash flow from present operations. Several small refiners found that the market would not accept the risk of financing such investments, so they have either shutdown, produce only heavy-end products such as asphalt, or have been converted to petroleum storage facilities. This is illustrated by the recent closures of Pacific Refining Company in Hercules and Powerine in Santa Fe Springs. For the remaining small refiners, the outlook is not encouraging if they are unable to generate the necessary volume to compete in gasoline markets outside California.

The refining industry has been able to compensate for the loss of refining capacity, during a time of growing demand, by increasing the refinery utilization rate from 71 percent in 1982 to 95 percent in 1993. This has enabled the industry to increase the production of petroleum products by 300 thousand barrels per day. This increase has been in response to an increase in the demand for light-end products, the most valuable of the refined products. The light-end products are motor gasoline, aviation fuels and distillates. The production of light-end products has increased 27 percent, going from 438 million barrels (1.2 million barrels per day) in 1982 to 559 million barrels (1.5 million barrels per day) in 1993. By contrast, the output of other products has remained constant (see Figure 2-5).[14]

In addition, the industry has improved the efficiency of its operations and has made improvements in refining process technology. However, with a utilization rate now at 95 percent, there is limited capability to increase product output on a sustained basis. Based on current information available from oil companies, California refineries have the ability to meet the demand for Phase 2 RFG in 1996, even under a high demand scenario. If California continues to lose refining capacity over the next decade and demand for refined products remains level or increases, then refiners have the option to either import additional volumes of finished products, import additional refined product blendstocks, or perform refinery modifications (such as debottlenecking).

In the short term, a major unscheduled outage may cause a temporary tight supply situation because of the high utilization rate. However, there are several options available which may help refiners to mitigate the tight supply. First, existing inventories of product and blendstock may be drawn down to meet demand. This option has been made more viable by increased storage capacity in the state as a whole. Second, refiners may seek a CARB variance to offset the volume of fuel lost by the outage. Third, additional refined products or blendstocks may be imported. However, such imports would involve a time delay for transportation from the U.S. Gulf Coast, the Northwest or the Pacific Rim, and would come at a higher cost. Because California is somewhat isolated from other major refining centers, the movement of products to the state could lead to a near-term tight supply situation. And since refiners outside the state may be reluctant to make the necessary investments to make large volumes of California-specific fuel, out-of-state refining capability may be limited. The unique fuel specifications for California's reformulated gasoline and diesel fuels could limit the availability of these fuels from outside California.

CHALLENGES FACING CALIFORNIA PETROLEUM FUEL MARKETERS

Finding a balance between environmental concerns, government revenue needs and business growth remains a substantial challenge confronting California. Conflicts between business and public interests are frequent. Petroleum product marketers have expressed several concerns with regulatory measures that have increased the cost of doing business in California. The following examples apply to underground storage tank replacements, fees for cleaning up fuel leaks, and tax collection policies.

In addition to CARB reformulated gasoline regulations which will further improve California air quality, regulations regarding fuel storage tanks are also protecting groundwater resources. The Public Health and Safety Code establishes requirements for underground storage of hazardous substances. As hazardous substances, petroleum fuels must be stored safely. The Code includes tougher standards that apply to underground petroleum fuel storage tanks built after January 1, 1984. Tanks constructed before 1984 must be upgraded or replaced by December 22, 1998. The regulations are intended to help ensure that groundwater supplies will be protected from contamination from all underground fuel tanks.

Petroleum product marketers cite the expense of tank replacement as an additional financial burden incurred by their business. The California Independent Oil Marketers Association estimates the cost of upgrading pre-1984 tanks to be $100,000 per tank. Low-interest loans are available for these upgrades provided the gross annual income of the company requesting the loan does not exceed 7 million dollars. Petroleum marketers are complying with the regulation, but foresee that some businesses may close as the deadline for compliance approaches.

The oil marketers association is also concerned with an upcoming increase in the fee collected to fund the cleanup of unauthorized releases of fuel, i.e., leaks. The Barry Keene Underground Storage Tank Cleanup Trust Fund Act of 1989 was established to make available the funds collected from the fee to see that corrective action is taken when leaks occur. The fee of 0.7 cents per gallon will increase to 1.2 cents per gallon in 1997. While the per gallon fee increase seems small, the large fuel volumes involved add up to a significant expense. Marketers will pay the increase up front, but consumers may likely see a corresponding small increase in per gallon fuel prices.

Changes in the way fuel excise taxes are collected and diesel storage requirements are also causing concern among fuel marketers. Before 1994, marketers were permitted 45 to 60 days after purchasing fuel to collect and pay federal and state excise taxes on the fuel. Effective January 1, 1994, for the federal tax and July 1, 1995, for the state tax, marketers must pay the tax at the time of purchase. These changes were instituted to eliminate tax fraud as well as nonpayment by marketers who may have gone out of business before the tax could be collected from their customers.

The change in tax collection presents an additional cash flow problem for some marketers. The additional operating capital needed to pay the tax up front by the marketer purchasing seven tankloads of fuel a day, for example, could amount to approximately $500,000 per month. While marketers now have a large incentive to recoup those funds by collecting promptly from their customers, it is an incentive they would rather do without.

A similarly motivated requirement for ensuring proper tax collection on diesel fuel went into effect January 1, 1994. Both off-road and on-road diesel fuel have the same chemical composition, but are identified differently for tax purposes. Off-road diesel is exempt from excise tax and is required to be dyed red to distinguish it from on-road diesel. "Clear" diesel for on-road use is taxed. The color difference requires that separate storage tanks be used to avoid commingling. The requirement makes the field auditor's job easier and helps assure proper tax collection. From the marketer's perspective, however, the expense of providing segregated storage in some cases has not warranted selling both red and clear diesel fuel. As a result, some marketers lost those customers who require the diesel fuel that the marketer no longer sells.

These examples demonstrate the trade-offs that can occur between environmental protection, government revenue needs and business growth. Smaller companies can be particularly affected by the expense of complying with environmental controls and have difficulty remaining competitive. On the other hand, government must act responsibly to protect public health and safety. In reducing the risk of environmental damage, consideration must always be given to the economic costs of regulatory measures.

ENDNOTES

1. Conservation Committee of California Oil and Gas Producers, ***Annual Review of California Oil and Gas Production 1993***, Table B-10a and M-1.

2. Conservation Committee of California Oil and Gas Producers, ***Annual Review of California Oil and Gas Production 1993***, Tables M-1 and M-4.

3. Testimony of Scott H. Stevens, Advanced Resources International, ***California Thermal Enhanced Oil Recovery (TEOR)***, 1995 Fuels Report Hearing, May 11, 1995.

4. Ibid.

5. Energy Information Administration, Form EIA-810.

6. Alaska Department of Natural Resources, ***Historical and Projected Oil and Gas Consumption***, March 1995.

7. Idaho National Engineering Laboratory for the U.S. DOE, ***Alaska North Slope National Energy Strategy Initiative, Analysis of Five Undeveloped Fields***, May 1993.

8. Both the Senate and the House of Representatives have approved legislation to lift the ban on exporting ANS crude oil. ANS oil could be traded on foreign markets early next year.

9. U.S. Department of Energy, ***Exporting Alaskan North Slope Crude Oil, Benefits and Costs***, June 1994.

10. Energy Information Administration, ***State Energy Data Report***, 1992.

11. Petroleum Industry Information Reporting Act (PIIRA) data has been collected since 1981 and includes information on refinery operations, petroleum and fuel stocks, imports and exports and petroleum fuel use.

12. Charles Greene Consultants, ***The Impact on California of Alaska's Crude Oil Production***, June 1993.

13. Throughput capacity varies depending on the gravity and viscosity of the crude oil being transported.

14. Submittals from oil companies under the Petroleum Industry Information Reporting Act.

Chapter 3

REFORMULATED FUELS AND RELATED ISSUES

INTRODUCTION

Reformulated gasoline (RFG) is a cleaner burning fuel than conventional gasoline that will significantly improve air quality by reducing emissions from all gasoline-burning motor vehicles and engines. RFG is required by the federal Clean Air Act Amendments and California Air Resources Board (CARB) regulations, and is considered a cost effective method to help achieve state and national air quality standards.

This chapter includes a summary of the federal and state regulations that brought about RFG. The chapter also includes a description of CARB's Phase 2 Reformulated Gasoline Advisory Committee and its subcommittees, and the recent transition to Environmental Protection Agency (EPA) Phase 1 RFG in California and the nation. Current CARB RFG issues such as fuel supply and demand, transportation and distribution, and potential marketing concerns are also summarized.

CLEAN AIR REGULATIONS

To help meet new clean air standards, both the federal and state governments have enacted legislation which mandates a change in the composition of gasoline to reduce motor vehicle emissions. Following is a timeline for the implementation of the new gasoline standards:

November 1, 1992: Implementation of CARB Phase 1 gasoline.

January 1, 1995: Federal RFG (EPA Phase 1) began to be sold at the retail level in the nine areas in the nation with the greatest ozone pollution and additional areas around the country which have voluntarily opted in to this program. Los Angeles and San Diego are the two mandated regions in California.

January 1, 1996: Leaded gasoline phased out on a national level.

March 1, 1996: CARB Phase 2 RFG required at the refinery level.

April 15, 1996: CARB Phase 2 RFG required at the terminal level.

June 1, 1996: CARB Phase 2 RFG required at the retail level for the entire state. Replaces the use of EPA RFG in California.

January 1, 1998: EPA RFG moves from the Simple Model, which tracks five fuel parameters, to the Complex Model, which tracks three additional fuel parameters. The temporary exemption from four CARB Phase 2 RFG fuel parameters ends for small California refiners.

January 1, 2000: EPA Phase 2 RFG goes into effect in the areas required to use federal Phase 1 RFG.

Federal RFG

The United States EPA required refineries to begin implementing Phase 1 of their RFG program on December 1, 1994, as mandated by the RFG provisions of the federal Clean Air Act Amendments. The use of this gasoline is expected to reduce various pollutants by 15 to 19 percent from 1990 levels. This fuel is required in the nine areas, nationwide, with the worst ozone pollution problem. The Los Angeles Basin and San Diego region are currently the two areas in California where use of EPA gasoline is required. These two regions represent 57 percent of the state's gasoline demand. Sacramento became the tenth area when it was redesignated from severe to serious on June 1, 1995, with program implementation to become effective 12 months later, on June 1, 1996.

Federal law requires reductions in auto emissions of volatile organic compounds (VOCs), a major cause of ozone formation in the summer months, as well as toxic air pollutants. The first stage of EPA Phase 1 RFG requires reduced benzene, lower Reid vapor pressure (RVP) specifications, added oxygenates, and heavy metal limitations.[1] The overall goals of federal RFG are to reduce ozone formation during the summer months and reduce toxic emissions year round.

In January of 1998, the second stage of the federal Phase 1 RFG program will require that refiners move from the Simple Model (five parameters for which compliance is judged) to the Complex Model, which introduces three additional parameters (sulfur, olefins and distillation range limitations). Prior to 1998, refiners have the option to use the Simple or the Complex Model to certify that their fuel meets EPA RFG requirements. Most refiners producing EPA RFG chose to use the Simple Model due to limitations of commingling the two types of formulations. Once the Complex Model option is selected, however, the refiner is not permitted to switch back to the Simple Model option. With these EPA parameters, performance standards are established and refiners are given flexibility as to how to meet the standards. This transition will not significantly affect California, which will already have been under CARB Phase 2 RFG regulations for two years.

Federal Phase 2 RFG will be delivered beginning in December 1, 1999, and will be required at the retail level in all areas outside California using federal Phase 1 RFG, beginning on January 1, 2000. This gasoline is expected to reduce oxides of nitrogen (NOx) by 5.5 percent, toxic air pollutants by 20 percent, and VOC by 27.5 percent. (These figures are calculated based on a 1990 model year vehicle as it would emit in 2000 if there were no Phase 1 program.) Within California, CARB Phase 2 RFG will continue to be required since, under current specifications, EPA Phase 2 RFG does not meet all of CARB's requirements. Specifically, the fuel property specifications for aromatics, olefins, sulfur and the distillation temperatures are higher for EPA Phase 2 than for CARB Phase 2.

California Air Resources Board RFG

Motor vehicles are the largest contributors to California's severe air quality problems, accounting for 50 percent of the emissions of VOCs and NOx (which combine to contribute to the formation of ground level ozone, the main ingredient in smog). CARB Phase 1 RFG, which was implemented in November 1992, set a limit on RVP, required detergent additives to control engine deposits, and completed the phase-out of leaded gasolines in California. According to CARB, the use of Phase 1 RFG was responsible for one-third of the mobile source air quality improvements from various air pollution reduction programs.

When compared to CARB Phase 1 RFG, CARB Phase 2 RFG has a lower RVP, aromatic hydrocarbon content, distillation temperatures, sulfur, and olefins, as well as added oxygenates. It will produce the largest emission reduction at one of the lowest costs per tons of pollution avoided of any of the various control measures employed to date. When compared to CARB Phase 1 gasoline, the use of CARB Phase 2 RFG will reduce emissions of VOCs by 17 percent, NOx by 11 percent and carbon monoxide (CO) by 11 percent. These reduction percentages are for all the onroad gasoline-powered vehicles in use during 1996.

CARB standards are more rigorous than EPA's Phase 2 requirements, setting precise specifications for eight fuel parameters. Significant improvement in air quality is expected and a reduction in emissions of cancer-causing pollutants, translating to an expected 40 percent decrease in the cancer risk due to the use of gasoline-powered motor vehicles. The resulting cleaner air will reduce breathing difficulties and lung tissue damage, as well as vegetation damage throughout the state. As an additional benefit, 20,000 temporary construction and several hundred permanent jobs were created as a result of these regulations.

CARB PHASE 2 RFG ADVISORY COMMITTEE

CARB formed an RFG Advisory Committee to identify potential problems and recommend solutions regarding the introduction of CARB Phase 2 RFG. The Committee is made up of officials from state energy, automotive, education and environmental agencies, as well representatives from automobile manufacturers, oil refiners and marketers, environmental organizations, and numerous other groups representing the broad interests of the state at large.

The Advisory Committee's purpose is to facilitate the introduction of CARB Phase 2 RFG in California by providing a forum for discussing issues and concerns with all parties affected by the production, distribution, and use of RFG. The Committee's intent is to monitor facility modification progress, examine performance issues and other problems, look at the supply and demand balance, and develop contingencies for potential supply disruptions. To serve the Committee's charge, three subcommittees have been established: Transition, Performance and Public Education.

- **Transition Subcommittee**: The purpose of this subcommittee is to evaluate the petroleum industry's ability to provide CARB Phase 2 RFG to meet the needs of California's motorists and discuss with the Advisory Committee possible measures that can be taken to minimize the impact of potential supply disruptions. This Subcommittee advises the full Advisory Committee, CARB and the Energy Commission on analysis of supply, demand, distribution and compliance information gathered separately by the two agencies. The Transition Subcommittee is also monitoring California's experience with the transition to federal Phase 1 RFG. This transition will prove a limited indicator of the market's flexibility and ability to meet the needs of the state's motorists.

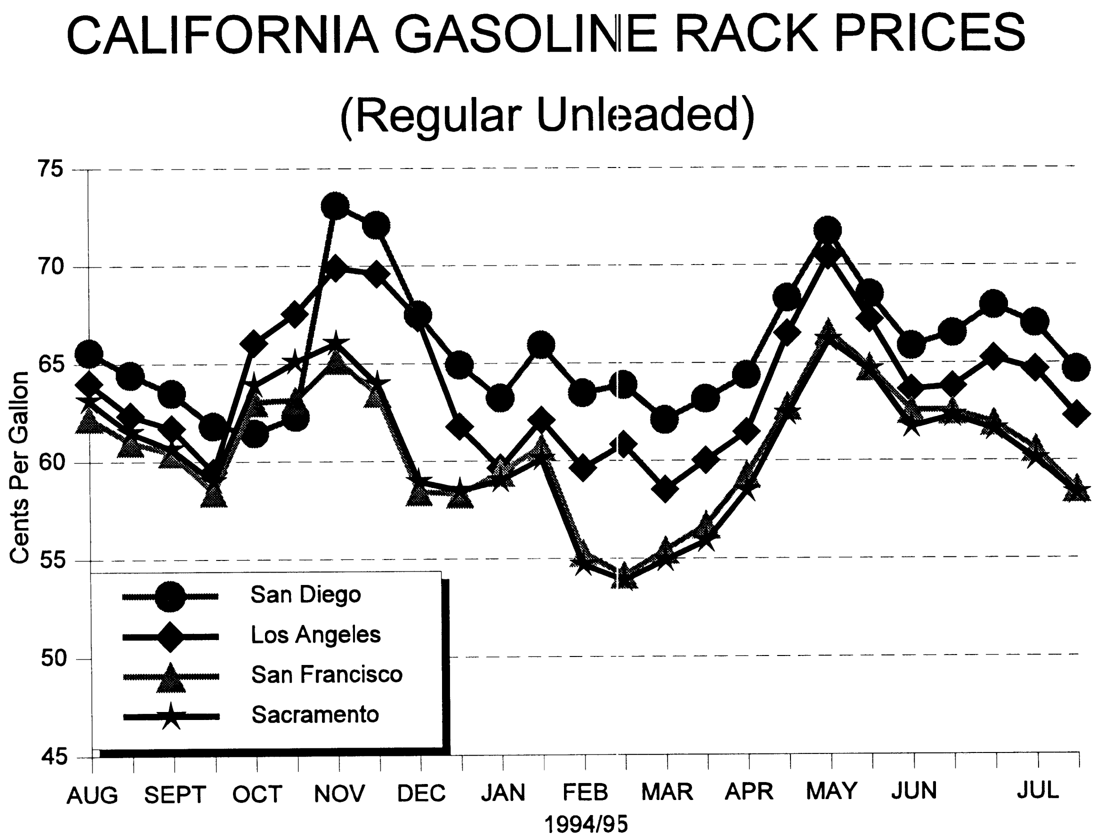
- **Performance Subcommittee**: This Subcommittee's purpose is to inform the Advisory Committee and the CARB on the design of fuel test programs for evaluating the performance of CARB Phase 2 RFG in motor vehicles, fuel storage systems and other equipment. The Performance Subcommittee will facilitate coordination of available resources for the test programs and provide advice regarding potential problems and solutions. This includes addressing performance concerns such as potential materials compatibility problems, additional maintenance, and emission reductions of the new fuel. This is done through on- and off-road test programs, conducted in the laboratory and the field. One such test program is the recent RFG Performance and Compatibility Test Program, which tests CARB Phase 2 RFG in more than 1,000 cars and trucks, as well as boats and utility equipment. The Performance Subcommittee's work also includes vehicle fuel system inspections and data collection on fuel economy.

- **Public Education Subcommittee**: The Public Education Subcommittee advises the full Advisory Committee and CARB on development and implementation of programs to educate industry, businesses, and governmental agencies, as well as the general public, about CARB Phase 2 RFG. Using input from the other Subcommittees, this Subcommittee is addressing the public's potential concerns using various outreach programs and educational resources. The goal of the Public Education Subcommittee is to effectively prepare the motoring public for the introduction of CARB Phase 2 RFG.

TRANSITION TO EPA PHASE 1 RFG

On January 1, 1995, the EPA Phase 1 RFG regulation took effect, requiring the use of less-polluting gasoline in the nine worst air quality areas in the nation, including six southern California counties plus voluntary opt-in areas outside of California. The transition to the new fuel at more than 5,000 service stations in Southern California went smoothly. This can be attributed to an adequate supply of EPA RFG in Southern California and the absence of production problems at the refineries as the result of careful planning by the refiners. Refinery production and inventories were at levels that would be expected for

Figure 3-1



this time period to meet demand. Deliveries to pipeline terminals were available in volumes similar to previous years.

Despite concerns about potential price spikes, the price of EPA RFG was lower than might have been expected to be needed to recover investments for making the new product and cover the cost of oxygenates required for wintertime gasoline. This temporary situation was probably a result of more than adequate supplies of EPA RFG. The wholesale gasoline price differences between Southern California cities (such as San Diego and Los Angeles) and Northern California cities (such as San Francisco and Sacramento) was relatively small before the introduction of EPA RFG. Since that time, this gap has increased, reflecting the additional cost of EPA RFG compared to conventional gasoline (see Figure 3-1).[2] Due to the unavailability of additional segregated storage tanks, Santa Fe Pacific Pipeline Company reduced the number of gasoline grades held in community tanks at the Colton terminal.

The most common complaint regarding the transition to EPA RFG is the administrative burden of the federal reporting requirements placed on the industry, including the difficulty in interpreting some of these requirements and the large volume of paperwork.

CARB PHASE 2 RFG ISSUES

The transition to CARB Phase 2 RFG will set California apart from fuel markets in all other states in the country in terms of fuel specification requirements. To provide this cleaner fuel to the California consumer, refiners have invested more than 4 billion dollars for facility retrofits. The Energy Commission is currently examining issues about the supply, demand, transportation, distribution and marketing of this California-specific fuel.

CARB Phase 2 RFG Supply and Demand

Energy Commission analysis of confidential data submitted by California refiners indicates that California refiners have the ability to meet a high demand scenario for CARB Phase 2 RFG through the first full year of the regulation, barring any severe unexpected refinery problems. Figure 3-2 illustrates maximum CARB Phase 2 RFG supply capacity compared to a high demand estimate of 2 percent increase per year.[3] The assumed demand change from 1995 to 1996 is actually 4 percent for this time period only, to adjust demand to account for the slightly lower energy content of CARB Phase 2 RFG compared to the various types of gasoline in use during 1995. Although the demand line exceeds the maximum supply volume during 1999, the Energy Commission expects that California refining companies will either import finished CARB RFG from outside California, import additional blend-stocks or make additional refinery modifications to expand RFG production capacities by this later date if gasoline demand were to actually grow at the high demand scenario rate.

A Most Likely Demand estimate contrasted with a Best Estimate of supply has also been prepared by the Energy Commission as part of the CARB RFG supply/demand balance. This analysis is based on supply data submitted by the oil companies and demand estimates prepared by the Energy Commission. Figure 3-3 illustrates that the Best Estimate of CARB Phase 2 RFG supply is adequate to meet estimated demand throughout the forecast period.

In addition to producing CARB Phase 2 RFG beginning in March 1996, refineries in California will continue to produce various types of conventional gasolines for export to meet contractual obligations, primarily in Arizona, Nevada and Oregon. California is a net exporter of finished products, transporting these fuels principally by pipeline to Reno, Las Vegas and Phoenix. In addition to pipeline transportation, some product is delivered by truck to Oregon from the Chico pipeline terminal. Figure 3-4 depicts the 1993 flow of gasoline from California.[4] Historically, Southern California refineries produce less gasoline than Southern California consumers use and the export markets in Las Vegas and Phoenix demand. This necessitates movement of refined product from Northern to Southern California by tanker or barge since currently there is no product pipeline connecting the two portions of the state.

Transportation and Distribution Issues

The introduction of CARB Phase 2 RFG in California will affect the transportation and distribution of finished petroleum products within the state. The two principal common carrier transporters of refined products in California are the Santa Fe Pacific Pipeline and CalNev Pipeline Companies. These pipeline companies are both intrastate and interstate carriers, transporting a variety of product grades and specifications.

In order to handle additional fuel grades, the pipeline companies have prepared for increased segregation requirements to avoid losing flexibility and capacity of their system. The pipeline companies have made the investment to construct new storage tanks and also to convert existing tanks to "drain dry" configuration with vapor recovery systems. This conversion increases flexibility by allowing a tank to be emptied completely of one product and filled with another, rather than being dedicated to only one product grade.

The pipeline companies currently transport four basic types of gasoline (leaded and unleaded regular, unleaded midgrade and unleaded premium), each with variations of octane, RVP, oxygenate, bromine, and sulfur content. Since October 1994, the pipelines have also transported Simple Model EPA RFG and RBOB (Reformulated Blendstock for Oxygenate Blending), both in three grades: regular (suboctane for RBOB), midgrade and premium. In addition, the companies transport three grades of diesel: CARB low sulfur/low aromatic, EPA low sulfur, and high sulfur off-highway.

Where there is not enough tankage at terminals to segregate all types and grades for every company, a community tank is used with uniform specifications set by the pipeline company. After March 1996,

Figure 3-2

California Maximum RFG Supply and Demand

High Demand Scenario

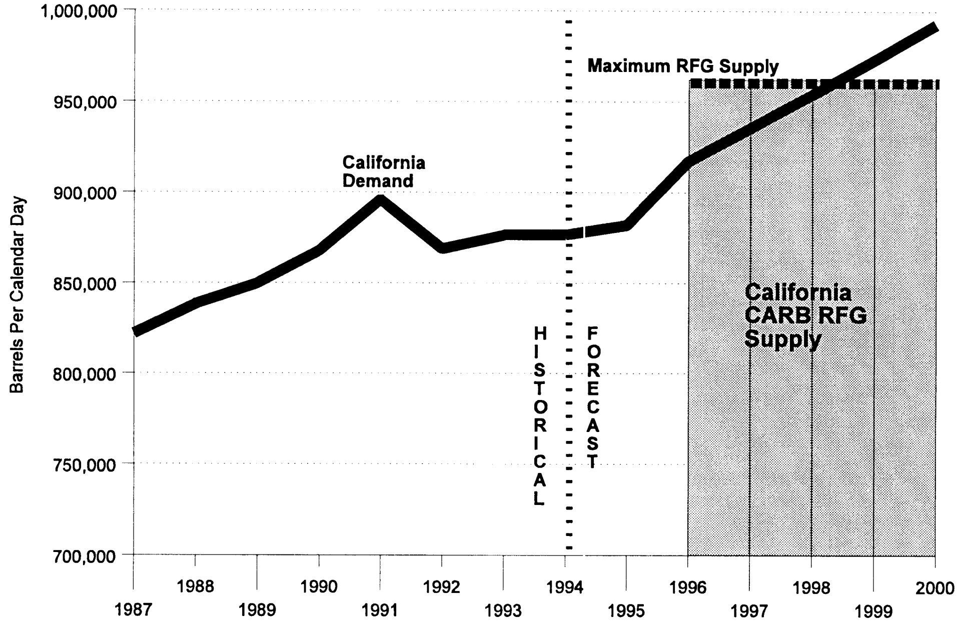


Figure 3-3

California Best Estimate RFG Supply and Demand

Most Likely Demand Scenario

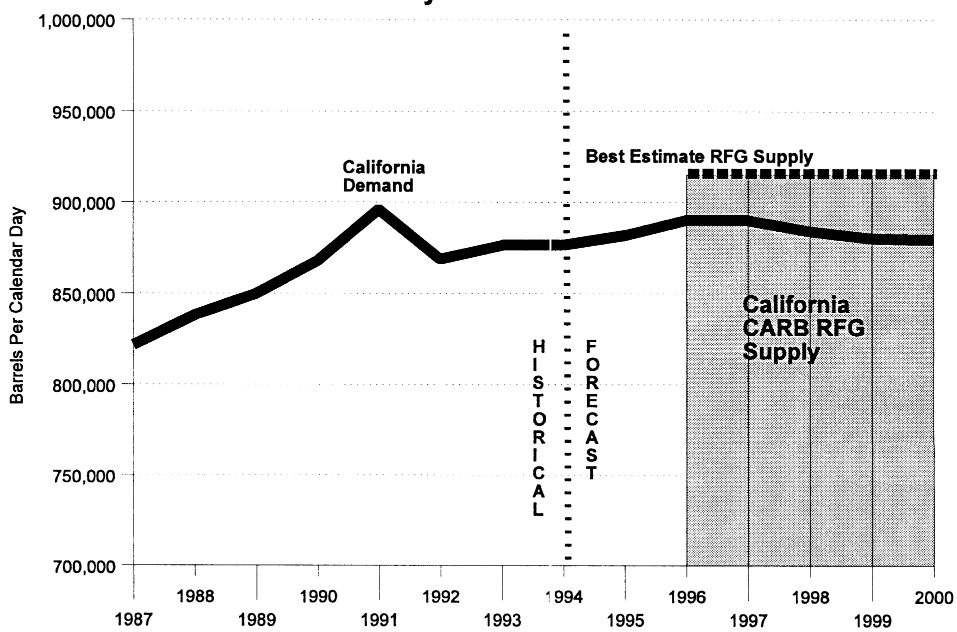
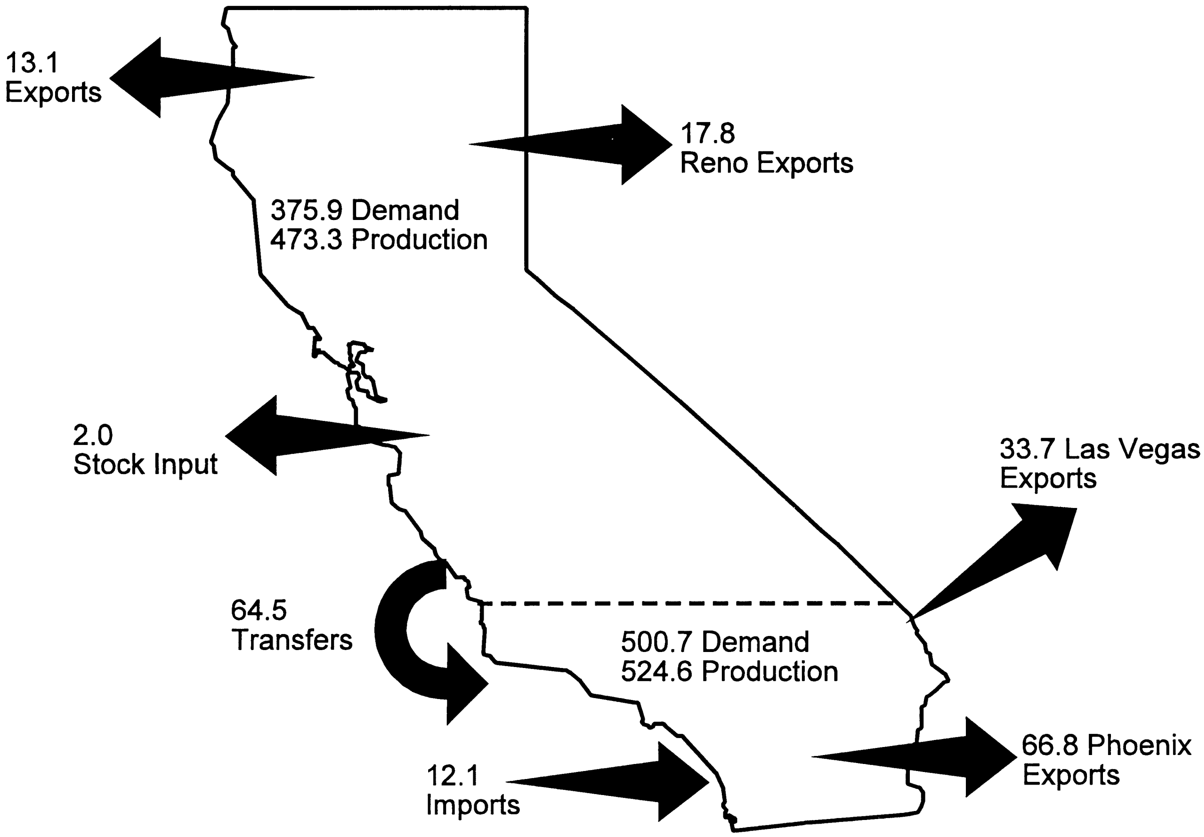


Figure 3-4

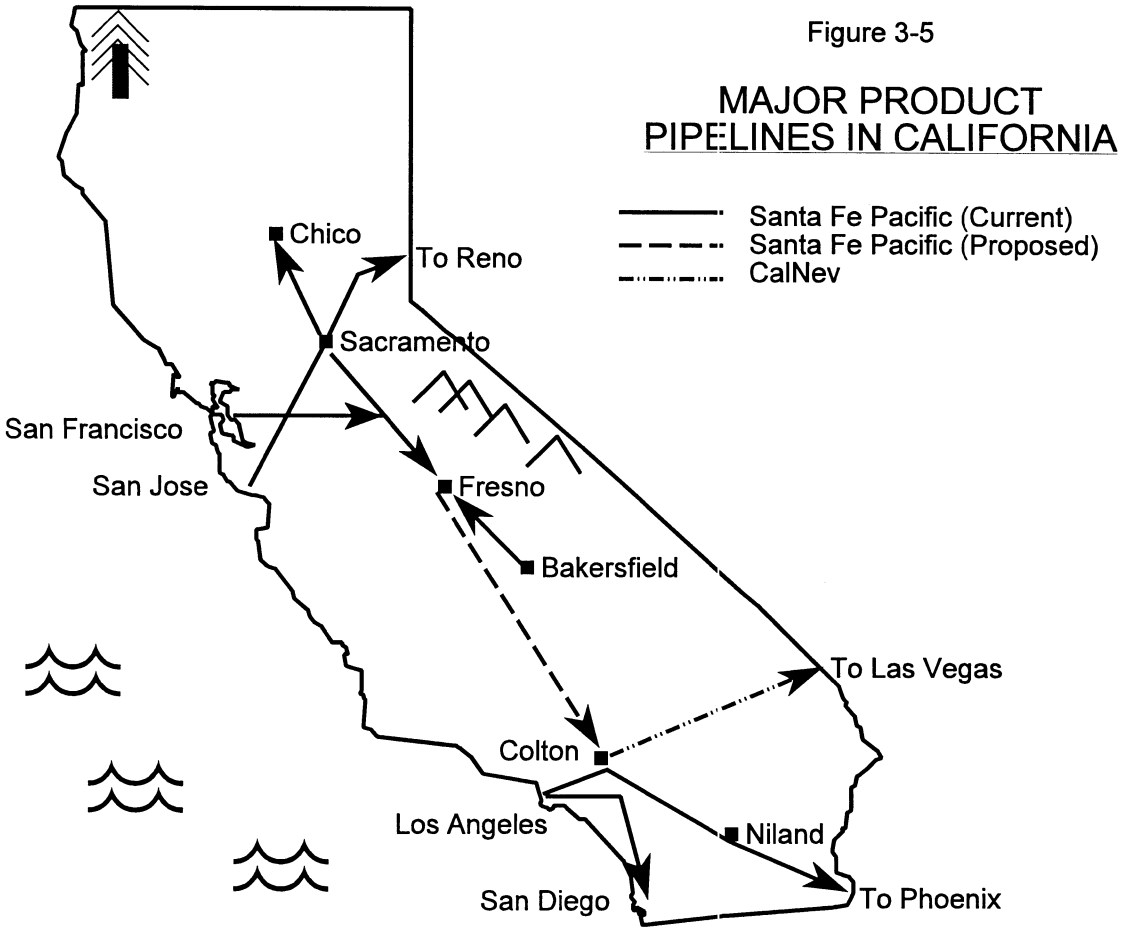
CALIFORNIA CONVENTIONAL GASOLINE
PRODUCTION AND MOVEMENT FOR 1993
(Thousands of Barrels Per Day)



some terminals may not be able to accommodate all grades for all companies. Pipeline operations are a complex, 24-hours a day system not only because of the numerous product grades to be transported, but also because of revisions in delivery schedules at the various locations. Although the pipeline company's shipping forecasters prepare monthly delivery schedules for each customer, changes are normally accepted up to seven days prior to pumping. In an emergency, when a refiner is unable to deliver the expected volume of product into the pipeline, last minute changes will be accepted to assist the shipper. A potential bottleneck with the transition to CARB Phase 2 RFG is the limited ability of the pipeline companies to handle product which does not meet specifications and must be segregated from other product which does meet the standard.

Santa Fe Pacific Pipeline Company is proposing a new petroleum product pipeline in California (see Figure 3-5). This proposed line would connect the terminus at Fresno south to their Colton facility in San Bernardino County. This project would effectively link Northern and Southern California, providing an economical alternative to transport product from Northern California refineries to markets in Southern California, Las Vegas and Phoenix. This situation could reduce the volume of product tankered or barged from north to south. As of the time of this report, the project is still in the engineering stage and will proceed to construction only if throughput demand warrants.

The use of tanker and barge transportation raises concerns about spills and accompanying environmental impacts. The Energy Commission has



examined the possibility that transition to CARB Phase 2 RFG may increase the volume of imported crude, product or blendstocks arriving in California by water. In 1992 a total of 3,887 tanker and barge trips were made into and out of California ports, 96 percent of which were made in the San Francisco and Los Angeles/Long Beach harbors. An Energy Commission assessment of California port facilities indicates, however, that a small to moderate increase in tanker movement would not overburden existing port facilities.

The San Francisco Bay received 1,100 tankers in 1993, roughly 92 tankers monthly, transporting 18.5 million barrels of crude oil and 8 million barrels of petroleum products per month. The tanker traffic has remained relatively flat over the past few years. Tanker movement into the San Francisco Bay is complex, partly by the need for large crude oil tankers to be lightered because of the shallower draft in the Bay and at the berths. This procedure transfers crude oil to smaller vessels, resulting in additional cargo transfer and congestion because of the length of time tankers are in port. Tankers (and barges) usually move in and out of port within 36 to 72 hours, depending on pump rate and volume of cargo. In addition, tankers (those carrying a cargo of 5,000 long tons or greater) entering the San Francisco Bay are required to use tug escorts from one mile west of the Golden Gate as a collision prevention measure.

The side-by-side ports of Los Angeles and Long Beach receive about 50 percent of the state's tanker volume. In 1993, 946 tankers arrived at the ports of Los Angeles and Long Beach. Of these, about one-third were foreign vessels, and the remainder were United States flagships. Tanker traffic into the ports has remained fairly constant in the last several years. Officials at the ports of Los Angeles and Long Beach foresee no potential bottlenecks resulting from modest increases in tanker traffic. In fact, they are seeking to attract additional business, and have plans to expand their facilities over the next few decades. The berth owners and operators also feel confident that no major constraints exist at the port.

Table 3-1 PROPERTIES AND SPECIFICATIONS FOR CARB PHASE 2 RFG				
Fuel Property	Units	Flat Limit	Average Limit	Cap Limit
Reid vapor pressure*	psi.	7	none	7
Sulfur	ppmw	40	30	80
Benzene*	vol. %	1	0.8	1.2
Aromatic hydrocarbons*	vol. %	25	22	30
Olefin	vol. %	6	4	10
Oxygen*	wt. %	1.8 - 2.2	none	1.8 - 2.7**
Temp. at 50% distilled (T50)	deg. F	210	200	220
Temp. at 90% distilled (T90)	deg. F	300	290	330

*Only these four requirements must be met by small refiners in 1996; the remaining four requirements must be met by March 1, 1998.
**There is no minimum requirement during the summertime for alternative formulations under the CARB predictive model. However, EPA does not allow the minimum to go below 1.8 percent in southern California and Sacramento (EPA Phase 1 RFG areas).

CALIFORNIA'S FUTURE CHALLENGES

Under the CARB Phase 2 RFG program, refiners may produce complying fuel, meeting the limits on eight fuel properties by one of four methods: flat limit, predictive model, averaging, or fleet test certification (see Table 3-1).

The predictive model is a mathematical equation designed to predict tailpipe emissions. If the calculated emissions reduction of a proposed alternative formulation, when compared to emissions from the Flat Limit or Averaging Limit formulas, is equivalent or better, then the formula can be submitted to the CARB for approval prior to production and shipment of the CARB RFG.

The CARB regulations also allow refiners the flexibility to average six of the eight fuel specifications over a 90-day period. If one component exceeds the averaging limit (but never exceeds the cap) in one batch, it can be offset by bringing the component under the averaging limit in a subsequent batch. CARB has amended this provision to include three 10-day extensions per year during the first two years of the program. While the averaging provision may provide some flexibility to refiners in meeting the RFG specifications, the predictive model may allow the refiners to take advantage of their individual refinery configuration differences.

Oxygenate Supply

CARB Phase 2 RFG is required to contain between 1.8 and 2.2 percent oxygen by weight. Under the CARB RFG predictive model, however, up to 2.7 percent by weight oxygen can be used. The regulations can be met by blending one of several types of oxygenates into the finished gasoline. Methyl tertiary butyl ether (MTBE) and ethanol are the two main oxygenates that refiners have used to meet the wintertime oxygenate requirement in California. Tertiary amyl methyl ether (TAME) and ethyl tertiary butyl ether (ETBE) are two additional oxygenates that will be either produced at certain California refineries or imported for use in the state. Some refineries currently have the ability to produce a certain amount of their required oxygenate on site, but this will permit the refiners to produce only approximately 15 percent of their own needs due to the limited availability of certain key feedstocks to create the oxygenates. The Energy Commission expects the remaining balance of the state's oxygenate needs to be imported from foreign and domestic sources.

Potential Marketing Concerns

The California petroleum fuel marketers are concerned about the need to separate different gasoline grades to ensure that the gasoline will remain in compliance with the regulations. The question arises whether CARB RFG produced by one supplier can be mixed with that produced by another supplier and still be within the limit for all eight fuel specifications. This is a particular concern if fuel containing MTBE is mixed with fuel containing ethanol since the resulting mixture may violate the RVP standard. EPA prohibits the mixing of gasoline containing MTBE with gasoline containing ethanol in EPA RFG areas. In addition, various suppliers may blend in different additives. If these fuels have to be segregated, then more storage capacity will be required.

Marketers are also concerned about remaining in compliance while distributing product from different suppliers. While they want enforcement that is not unnecessarily burdensome, the industry recognizes that a monitoring system is needed to prevent the deliberate sale of non-complying fuel in California. Currently, where fungibility of a product is not a problem, the non-contract marketer can purchase products from the supplier with the lowest price, without being confined to California. For example, marketers in the extreme northern portion of California may currently choose to obtain fuel from either a terminal in southern Oregon or at the Chico pipeline terminal, whichever has the lower price. This business practice may change if certain out-of-state terminal operators decide not to carry CARB RFG.

Regional Refining and Fuel Specifications

The Energy Commission has reviewed the advantages and disadvantages of establishing common fuel specifications for the western states located in the Petroleum Administration Defense District V (PADD V): Arizona, California, Nevada, Oregon and Washington. (Alaska and Hawaii are also in PADD V but their products are supplied primarily by local refineries.) Western refineries produce gasoline and distillates (primarily diesel) for distribution in more than one state, complying with more than one set of fuel specifications.

The western states have three refining areas, each with its own distribution system: Los Angeles, San Francisco and the Puget Sound area of Washington. Refiners in Los Angeles supply Southern California, Phoenix and Southern Nevada. Refiners in San Francisco supply Northern California, Northern Nevada and Southern Oregon, where fuel is transported by truck from the Chico pipeline terminal. Refiners in Washington are the primary product suppliers to Oregon and Washington, with a small amount of both finished and unfinished products currently tankered to California. Within each area supplied by west coast refiners, different air quality conditions exist.

Even though all the western states use oxygenated gasoline, California's CARB diesel and Phase 2 RFG establish stricter specifications than the EPA Phase 1 gasoline and diesel used in the other states. One advantage of other states using the cleaner fuel is the air quality improvement to be gained even though the other states do not have the same severity of air quality problems. However, the use of RFG may not be the least cost program in other states where other less costly air pollution control measures have not yet been implemented.

The regional use of CARB Phase 2 RFG and diesel could improve economies of scale, reducing the per-unit capital costs of refining, as well as distribution and storage costs because of the reduced demand for segregated storage. Refinery modification for RFG may also increase the gasoline yield, although that amount cannot be confirmed until actual production begins March 1, 1996. The economies of scale advantage could have been realized if supplying regional demand had been included during the design phase. As it stands now, it may be expensive for most refineries to expand CARB RFG production to meet regional demand, requiring the construction or expansion of certain units, principally alkylation units.

ENDNOTES

1. Benzene and other aromatic hydrocarbons, such as toluene and xylene, are characterized by ring structures of carbon atoms. Aromatics are a factor in determining the temperature at which gasoline burns. Limiting aromatics content in gasoline will reduce the emission of volatile organic compounds (VOCs), Nox and toxics. RVP is a measure of a liquid's volatility, or tendency to evaporate, in pounds per square inch. In gasoline, lower RVP means less evaporation and, consequently, less emissions of VOCs.

2. Oil Price Information Service newsletter.

3. Joint ARB/CEC survey forms.

4. Information submitted by oil companies under the Petroleum Industry Information Reporting Act.

Chapter 4
ALTERNATIVE TRANSPORTATION FUELS IN CALIFORNIA

INTRODUCTION

The introduction of alternative fuels into California's transportation market has been gradual because these fuels compete with gasoline and diesel, fuels which have been in plentiful supply at low prices. But, with an uncertain long-term future for oil supplies and prices, alternative fuels may have a more substantial and important role. As discussed in Chapter 1, a future of higher world crude oil demand and prices could occur, depending on demand growth in developing nations and future world oil production levels. In light of this possibility, conserving and diversifying energy resources remains an appropriate objective. Developing and commercializing alternative fuels is one potential means for diversifying an energy resource base for the transportation sector. Largely as a result of environmental regulations and recent energy legislation, and in spite of difficult existing market conditions, there is a potential for the entrance of an estimated one million alternative fuel vehicles (AFVs) into the California market in the next 10 years.

The appropriate role for government is to maintain the viability of alternative fuels as long-term options while allowing market forces to determine the appropriate mix of fuels for transportation use. There has been a great deal of progress in developing vehicle technology, refueling infrastructure and consumer acceptance of alternative fuels since the oil embargoes of the 1970s. In the interest of maintaining maximum flexibility to respond to changing world oil markets, the state should sustain this progress by identifying and mitigating barriers to the use of alternative fuels. This preparation will reduce the lead time necessary to respond to volatile world oil prices with rapid shifts in market shares of alternative fuel use.

This chapter discusses four major factors which affect the marketing of alternative fuels: the availability of AFVs, the cost of owning and operating AFVs, the supply of alternative fuel (primarily the number and location of fueling sites), and the price competition between alternative fuels and conventional fuels. First, there are few AFV models being offered by manufacturers. Second, those vehicles that are available can carry a high incremental price over comparable gasoline fueled vehicles. Third, most alternative fuels are available only at a small number of refueling locations. Fourth, the cost of using alternative fuels, including fuel price and operating costs, may be higher for several applications when compared to conventional fuels. Consequently, because of these four factors, demand for alternatives by consumers may be slow to materialize.

AVAILABILITY OF ALTERNATIVE FUEL VEHICLES

As a requirement of Assembly Bill 234 (Chapter 1326, Statutes of 1987), the Energy Commission regularly updates information on the availability and price of alternative transportation fuels and vehicles.

Table 4-1
CURRENT AND PROJECTED NUMBER OF AFVs IN CALIFORNIA*
(Thousands of Light Duty Vehicles)

Fuel Type	1994	2005	2015
Gasoline	21,723	24,740 - 24,754	26,797 - 26,823
Propane	40	45	51
M85	11	159 - 174	262 - 294
CNG	6	235	452
Electric	0.6**	594***	1,709***
Total AFVs	57.6	1,033 - 1,048	2,474 - 2,506

*Ranges are estimated using high and low M85 price projections. With lower M85 prices, the number of M85 vehicles may increase. At the same time, numbers of conventional vehicles and, to a lesser extent, other AFVs may decline. M85 is 85 percent methanol and 15 percent gasoline.
This number was obtained from the ***Electric Vehicle Association of the Americas Brief, Electric Vehicle Population of the United States*, March 1995. Previous estimates from Department of Motor Vehicle (DMV) data of EV use (1,200 EVs) in California appeared in the ***Calfuels Plan Report***, September 1994. These numbers are not comparable because of apparent data discrepancies with the classes of EVs in the DMV database and inclusion of non-highway EVS (i.e., golf carts and forklifts).
***Assumes full implementation of ARB's zero emission vehicle mandate.

Results of this analysis show that progress with introducing AFVs in California's transportation energy market continues at a gradual pace, limited by a variety of market and regulatory uncertainties. In 1994, approximately 40,000 propane vehicles, 11,000 M85 flexible fuel vehicles (FFVs), 6,000 compressed natural gas (CNG) vehicles and 600 electric vehicles (EVs) were in use in the state. Collectively these AFVs amount to only a small fraction of California's total light duty motor vehicle stock of almost 22 million. However, Energy Commission staff's preliminary base case projections, developed in response to Senate Bill 1214 (Chapter 900, Statutes of 1991), indicate that within the next 10 years the number of AFVs operating in the state could potentially reach over one million (see Table 4-1).

The current forecast is much lower than previous staff forecasts which indicated 5.8 million AFVs by 2005. The current forecast reflects revisions to the assumptions in the base case due to changes that have occurred over the past two years: the price for methanol staying higher than gasoline, reduced numbers of refueling stations for alternative fuels, and fewer choices of AFV makes and models. In addition, the current base case forecast assumes for the 20-year planning horizon that staff "most likely" fuel prices, all currently planned and adopted rules and regulations, and current vehicle manufacturers' plans will be in effect.

Three factors will help determine whether the staff's current projections are realized: government regulations supporting the introduction of AFVs, the number of models being introduced by major auto manufacturers, and the application of alternative fuels in heavy duty vehicles.

Government Regulations

Significant market inroads for AFVs appear forthcoming in response to federal and state energy and air quality initiatives. The most significant of these are the National Energy Policy Act of 1992 (EPACT) and California's low-emission vehicle regulations.

EPACT: EPACT requires federal and state government fleets, energy supplier fleets, and potentially most other public and private fleets to acquire increasing percentages of AFVs as part of their total fleet composition. EPACT requires that

AFVs constitute at least 75 percent of federal and state fleet purchases and 90 percent of fuel-provider fleet purchases of light duty vehicles by 2000.

California's Low-Emission Vehicle Regulations: California's low-emission vehicle regulations require auto makers to sell increasing numbers of vehicles with much lower emissions, including a sales fraction of zero emission vehicles (ZEVs). All auto manufacturers must comply with rules regarding transitional, low and ultra-low emission vehicles. The original regulations mandate that 2 percent of each of the largest manufacturer's light duty sales in California must be ZEVs by 1998, increasing to 10 percent by 2003. Smaller manufacturers are exempt from the ZEV rules and intermediate manufacturers have more time to comply. Based on this mandate, Energy Commission staff analysis indicates that the number of light duty ZEVs sold in California in 2003 may be approximately 132,000. The ZEV mandate is the major focus of the auto industry as it continues to work with California to clarify the types of vehicles which qualify for credit toward the ZEV requirement. For example, CARB staff is currently determining the feasibility of allowing manufacturers of technologies that can achieve extremely low tailpipe emissions, such as hybrid electric vehicles, to receive at least partial ZEV credit.

As a result of ongoing workshops sponsored by the California Air Resources Board (CARB), a number of amendments to the original ZEV mandate are under consideration. Although the recently proposed changes to the regulation still require that 10 percent of all vehicles offered for sale in 2003 meet the zero emission standard, the gradual phase-in (2 percent in 1998 and 5 percent by 2001) has been proposed to be modified to allow a market-driven approach that will actually result in the introduction of ZEVs as early as 1996.

Phase II Auto/Oil Study

The Auto/Oil Air Quality Improvement Research Program was established in 1989 by 14 oil companies and three domestic automakers to develop data and understanding of the influence of fuel properties on the emissions characteristics of automobiles and resulting ozone impacts in selected smog impacted urban areas in the United States. The objective of the research effort is to assist legislators and regulators to meet the nation's clean air goals.

This is a large, formal program with a planned time horizon of about six years and a budget close to 40 million dollars.

The program is comprised of two phases. The main conclusion of Phase I, derived from nearly four years of testing which concluded in 1993, was "...changing fuel composition variables can alter exhaust mass emissions and help reduce ozone formation in urban areas." The data generated under the program has helped CARB establish gasoline specifications for its CARB Phase 2 reformulated gasoline (RFG) program and reactivity adjustment factors under its Low Emission Vehicle and Clean Fuels Program.

Phase II of the program expanded on Phase I efforts by exploring additional fuel property influences such as effects of very low sulfur. Phase II expanded the alternative fuel test efforts to include M85 in production FFVs, methanol in dedicated vehicles, ethanol (E85 fuel) in FFVs, and liquefied petroleum gas (LPG) and compressed natural gas (CNG) in dedicated vehicles. A major element of this phase is testing of CARB Phase 2 RFG in both old and new gasoline car fleets. While testing under this phase of the program is nearly complete, final technical and ozone modeling reports have not yet been issued. All these reports should be available by the end of 1995.

With regard to reformulated gasoline energy content, Auto/Oil testing has shown that CARB Phase 2 RFG will cause a fuel economy penalty on the order of 3 percent to 4 percent when compared to conventional gasoline without oxygenates. This implies a numerically similar increase in California gasoline demand absent other factors which may alter consumers' driving habits in 1996 when CARB Phase 2 RFG will be sold throughout the state. The gasoline in use during 1995, however, is a combination of conventional, winter oxygenated and EPA RFG. Therefore, the energy penalty compared to this combination of gasolines is expected to be less than the 3 percent to 4 percent range.

Testing has also conclusively shown that these flexible fuel vehicles will attain the energy equivalent fuel economy of conventional gasoline vehicles while operating on M85 fuel. This is 6 percent to 7 percent higher than results obtained on either industry average (current) or CARB Phase 2 RFG. Energy Commission staff analysis of the Auto/Oil data shows that CARB Phase 2 RFG in FFVs will achieve ozone benefits close to those of M85 fuel,

Table 4-2
AFV MODELS AVAILABLE IN CALIFORNIA*
(1995 Model Year)

TYPE	FUEL	MANUFACTURER	MODEL	INCREMENTAL PRICE
Light Duty	M85	Ford	Taurus	$560
		Chrysler	Dodge Intrepid	$150
	CNG	Chrysler	Dodge Caravan Plymouth Voyager Dodge Ram Pickup Dodge Ram Van/Wagon Dodge Dakota Pickup	$4,500
Medium and Heavy Duty**	Methanol	DDC/TMC	Transit Bus	$40,000
		DDC/Carpenter	School Bus	$20,000
	CNG	Cummins/BIA	Transit Bus	$80,000
		DDC/Various	Buses and Trucks	$40,000
		Blue Bird/John Deere	School Bus	$12,600
		Hercules	Medium Duty Truck	Not Available
		Crane Carrier/Cummins	Refuse Truck	$49,000
	Propane	Ford	F600 & F700 Trucks	$1,000
		Caterpillar	Truck	$40,000

*This table does not include after market conversions or test vehicles.
**Except for the Ford propane truck, these incremental prices for various heavy duty AFVs can vary on a case-by-case basis due to bid specifications, number of vehicles in bid, etc.

but M85 fuel will achieve emission levels of cancer-causing pollutants 50 percent lower than CARB Phase 2 RFG.

Alternative Fuel Vehicle Models

The availability of alternative fuel models in the California new vehicle marketplace continues to be limited to a small selection of models offered by several United States manufacturers (see Table 4-2).[1] Only a few additional AFV models from these domestic manufacturers (and none from foreign manufacturers) are scheduled for upcoming model years. Conversions of some types of conventional vehicles to AFVs (typically propane or CNG) by a number of California companies offering conversion services has been an option in the past. However, new air quality regulations for such conversions impose new costs and technical requirements that may limit future AFV conversions. Thus, the narrow range of available, affordable AFV options will likely remain a major near-term obstacle to fleet operators or others seeking to employ alternative motor fuels. Continuing progress in reducing new gasoline vehicle emissions is having an important effect on auto industry development and marketing of AFVs. The use of cleaner-burning alternative fuels such as M85 and CNG is not receiving as much emphasis in light-duty vehicle emission-reducing strategies as previously expected. The combination of gasoline reformulation and advances in automotive emission control technology appears to be making the exhaust emission levels required by California's low-emission vehicle standards achievable without relying on the use of alternative fuels.

For example, for the 1995 model year, 12 different domestic and foreign auto makers have a total of 23 gasoline light-duty vehicle models certified as meeting the state's "Transitional Low-Emission Vehicle" standard. Testing of several advanced pre-production vehicle models is also demonstrating the ability to comply with the more stringent "Low-Emission Vehicle" and "Ultra-Low Emission Vehicle" standards using CARB Phase 2 reformulated gasoline.

One promising new approach that may improve the picture for near-term AFV model availability is a practice being instituted by Ford Motor Company referred to as their "Qualified Vehicle Modifier" program. Ford is working with selected aftermarket conversion companies to offer certain AFV models, converted by the QVM, with full corporate involvement and support. This may help bridge the gap between assembly-line produced AFVs and traditional AFV conversions by allowing customers to purchase a "new converted" AFV that has the benefit of the auto maker's technical, sales, service and warranty support. Ford will introduce the QVM option in California in the 1996 model year with three natural gas models and one electric model. Initial regulatory and marketplace results of Ford's QVM venture are likely to determine the extent of further auto industry interest in this approach.

Other than Ford's QVM plans, auto maker announcements of new AFV model availability in California have not been forthcoming. General Motors, which previously offered both M85 and CNG models, has yet to formally re-establish its AFV production plans. Chrysler will also discontinue its M85 vehicle model offering in 1996, but will maintain availability of its current CNG models.

Heavy-Duty Vehicles

Heavy-duty engine and vehicle manufacturers may be facing a more difficult emission control challenge with diesel-fueled engines, and are therefore devoting more development effort to alternative fuel options. Besides the currently available heavy-duty AFV models, additional alternative fuel heavy-duty engines are under development by Caterpillar (methanol, CNG, LNG and propane), Ford (methanol and CNG), Mack (CNG and LNG), Navistar (methanol), Cummins (methanol, CNG and LNG) and John Deere (CNG).

AFV COSTS

Prospective AFV owners in California, primarily fleet operators seeking options for compliance with the requirements of EPACT, do not yet have a wide array of new vehicle market choices. Considerable incremental prices continue to be charged for most of the AFV models, while most incentives that have been available to help offset these extra purchase costs are expiring. Converting gasoline vehicles to alternative fuel (CNG or propane) use may still be a feasible option for some fleets, although the cost of such conversions may exceed that of new AFV models because of emission certification requirements.

Expected fuel cost savings from using some alternative fuels should at least partially offset additional AFV purchase costs, but full cost recovery appears achievable only in cases of extremely high vehicle operating mileage. Clearly, in the absence of stronger regulation or other incentives, a more complete range of AFV models combined with lower incremental purchase prices and/or lower fueling costs will be needed for alternative fuels to be more widely used in the fleet sector and ultimately by the public.

M85: M85 FFVs have been a primary option for EPACT compliance by federal government fleets, the first to face the AFV acquisition requirements of the Act. Further reliance on this option for fleet compliance will be more difficult since the Ford Taurus is the only remaining FFV model available, and the incremental price of this model is scheduled to increase to $1,200 for the 1996 model year. With M85 currently priced higher than gasoline (on an energy-equivalent basis), owning and operating this vehicle would cost a fleet operator between 10 and 15 percent more than the gasoline model, or about three cents more per mile on average. Of course, the operator can avoid the additional operating cost by electing to refuel FFVs with gasoline.

CNG: CNG vehicles have also been acquired in increasing numbers recently by the federal government and other fleet operators. The prevailing incremental prices of CNG models (e.g., $4,500 for Chrysler's models) dominates the economics of owning and operating these vehicles. Even with natural gas priced below gasoline, less than one-half of the incremental purchase cost would be paid back in fuel savings over 100,000 miles of operating a typical vehicle (assuming a fuel economy equivalent to 20 mpg). If the price advantage of natural gas diminishes as forecasted, overall CNG vehicle economics will look even less attractive, unless the incremental vehicle purchase prices are reduced substantially. The high cost of CNG refueling installations poses a further economic obstacle to the use of CNG by fleets that cannot rely on the commercial network of fueling stations.

Propane: Propane vehicles continue to be used by some fleets, although the lack of new vehicle availability and questions over the continued viability of vehicle conversions clouds the future of propane as an EPACT compliance option. In the past, fleet operators who could obtain conversions at reasonable cost (or even perform their own in-house conversions), and who could obtain propane fuel supplies at one-fourth to one-third less than gasoline, realized a payback on their vehicle conversion investment within five years or less. A number of fleet operators elected to use propane based strictly on their own economic decisions, apart from any EPACT or other regulatory influence. The forecast shows a continued price advantage for propane over gasoline indicating that this alternative fuel option will continue to be selected by some fleets if vehicle availability is adequate.

Electricity: Although certain electric vehicles such as the General Motors Impact, Ford Ecostar, Honda Civic, Chrysler TE Van and others are currently being demonstrated, production run prices remain uncertain. Due to recent modifications to the ZEV regulations, some automobile manufacturers will actually be making their initial offering of ZEV models as early as 1996.

A number of smaller companies offer converted EVs, some of which are being operated in the state, primarily in electric utility company fleets. Prices of these converted vehicles, however, are not reliable indicators of future prices of auto industry-produced EVs. Thus, while forecasted electricity prices show an expected energy operating cost savings over gasoline -- over a 50 percent savings in utility service areas with the lowest rates -- determining the overall comparative costs of EV ownership and operation requires actual EV sales prices.

AVAILABILITY OF ALTERNATIVE FUELS

Fuel supply is not expected to be a major constraint to the near-term growth of motor fuel markets for any of the major alternative fuels. Availability at an adequate network of refueling sites to allow unrestricted AFV travel in the state is, however, likely to remain a constraint.

M85: M85 is now available at 55 public refueling stations in California, concentrated in urban regions where fleets with M85 vehicles are headquartered. Prospects for substantially expanding this limited M85 fuel station network remain uncertain. However, a "fuel station trigger" contained in state air quality regulations could require gasoline suppliers to make M85 available at more locations in the South Coast Air Basin, and other areas that "opt in" to the program, once cumulative sales of certified low-emission M85 vehicles in California reach the 20,000 level. Individual fleet operators with M85 vehicles may find it advantageous to install their own on-site M85 fueling facilities. A number of these installations are already in place. The flexible fuel M85 vehicles currently produced are also capable of using gasoline and thus are not dependent on M85 refueling stations.

CNG: California natural gas utilities are expanding the state network of CNG vehicle refueling stations. By the end of 1995, about 100 public access stations and 75 additional fleet installations are expected to be in operation. Further expansion of the CNG refueling network is contingent, in part, on the California Public Utilities Commission authorizing utility funding for this type of investment. Most CNG vehicles placed in service are dedicated (CNG only) vehicles, and are therefore dependent on adequate access to refueling stations.

Propane: Propane is reportedly available for vehicle refueling at more than 1,000 locations in California, making it the most widely-available alternative to gasoline and diesel fuel. It is unknown how many of these locations are equipped to refuel a significant number of motor vehicles and, most importantly, how many offer competitive motor fuel prices. Fleets with propane vehicles typically have motor fuel arrangements with propane suppliers for on-site refueling installations and/or access to designated supplier-operated stations.

Electricity: Electricity for EV charging can be made available anywhere there is electric service, a suitable charger (sometimes incorporated in the vehicle) and adaptable plug-in. However, special provisions are necessary to obtain electricity priced for EV charging at rates considerably lower than standard electric rates. As of June 1995, there were approximately 34 public access EV charging stations (166 outlets) and 79 private stations (194 outlets) located throughout the state.[2] While some utilities are installing a limited number of public EV charging facilities, most charging is expected to be accomplished during "off-peak" (late night, early morning) hours at the vehicle's base location. This typically requires installing proper wiring circuitry, separate meter and a charger, if the latter is not part of the vehicle equipment.

TRANSPORTATION FUEL PRICE PROJECTIONS

Table 4-3 shows Energy Commission staff estimates of retail (delivered, fully taxed) fuel prices for the years 1994, 2005 and 2015. Once the introduction of reformulated gasoline is complete, the long-term prices of petroleum-based transportation fuels should be relatively stable over the next 20 years. As shown in the table, petroleum prices are projected for two oil and natural gas price scenarios, termed the "base case" and "low case." While the fuels price forecasts do not specify a high fuel price scenario, the Energy Commission recognizes higher prices as a possible outcome that would dampen transportation demand accordingly. For the base case, crude oil prices are projected to grow at about 2 percent per year in real dollars. For the low case, crude oil prices remain level in real terms for about 10 years, then rise about 1 percent per year for the next 10.

This translates into petroleum product prices that are relatively level for the base case and declining in the low case (after the period of introducing reformulated fuels), assuming that excise tax levels remain fixed.

Assuming that fuel taxes remain at present levels, the staff fuel price forecasts project little change in the current price relationships between most alternative fuels and petroleum fuels. This would make it difficult for alternative fuels to improve their marketplace competitiveness. Following is a brief summary of the forecasted fuel price trends for the major alternative fuels compared with petroleum fuels. A more detailed fuel price forecast discussion is provided in a staff report entitled ***1995 Transportation Fuel Price Analysis***.

CNG: CNG prices for the two cases were based on projections of core commercial gas rates consistent with oil prices for each case, plus a margin to reflect the costs of refueling station equipment, the cost of compression, and state and federal taxes. This cost-based calculation was assumed to represent prices as they will be when California makes the transition from current subsidized rates to a competitive regime, around the year 2000. In the period prior to 2000, prices are expected to rise. Once the transition is complete, real CNG prices are projected to decline in both the base and low cases. Without an increase in its taxation, CNG would still be less costly than gasoline in the 2000 to 2005 time period, but lose any price advantage over diesel.

M85: Due to the extreme volatility of the methanol market experienced in the last two years, staff projected a range of M85 prices for both the base and low cases. In each case, this is represented by a band ranging from about 10 cents (real) per gasoline equivalent gallon lower than reformulated gasoline to about 30 cents higher for the long term. In the short to mid-term, M85 is expected to be somewhat higher priced than gasoline for both cases, until the market for methanol stabilizes. From its 1994 retail price position of about 43 percent more costly than gasoline, M85 is projected to be between 8 percent less costly and 26 percent more costly than gasoline in California by the year 2005.

Propane: Propane is expected to maintain its slight historical price advantage over gasoline, at least for

Table 4-3
COMPARATIVE FUEL PRICES*
(1993 $/Gasoline Equivalent Gallon)[3]

FUEL	BASE CASE 1994	BASE CASE 2005	BASE CASE 2015	LOW CASE 1994	LOW CASE 2005	LOW CASE 2015
RFG	1.15	1.42	1.45	1.15	1.32	1.28
CNG	0.80	1.17	1.16	0.80	1.08	1.02
M85	1.64	1.33 - 1.77	1.37 - 1.83	1.64	1.22 - 1.66	1.20 - 1.66
Diesel	1.19	1.18	1.20	1.19	1.08	1.04
Propane	0.97	1.15	1.15	0.97	1.08	1.04
Electricity** (cents/kwh)	4.7 - 10.4	4.9 - 10.6	5.0 - 10.9	4.7 - 10.4	4.9 - 10.6	5.0 - 10.9

*For purposes of this table, staff assumed that RFG (in 2005 and 2015) and all alternative fuels achieve equal vehicle fuel economy when compared to conventional gasoline (RFG in 1994) on an energy consumption basis. Caution should be exercised in using these prices to compare gasoline with AFV per mile fuel costs. Actual engine thermal efficiencies (and therefore energy consumption, fuel economy and fuel cost per mile) may be higher or lower than comparable gasoline vehicles depending on the maturity of the AFV technology.

**Electricity fuel prices cannot be put in terms of gasoline equivalent gallons. Although electricity fuel prices appear to be orders of magnitude higher than the price of other fuels, the high fuel efficiency of EVs makes actual fuel costs comparable to or lower than other fuels.

customers (e.g., fleets) able to take advantage of competitive motor fuel supply pricing (vs. small-volume pricing to recreational vehicle and other markets). However, propane appears unlikely to become much less costly than diesel.

Table 4-4
TAXES APPLIED TO SALES OF HIGHWAY MOTOR FUELS IN CALIFORNIA
(Dollars as of mid-1995)

FUEL	Federal Excise Tax*	State Excise Tax*	State/Local Sales (Average Percent)
M85	0.1140	0.09	7.9
CNG**	0.0485	0.07	none
Propane/LNG**	0.183	0.06	7.9
Electricity***	--	--	--
Gasoline	0.184	0.18	7.9
Diesel	0.244	0.18	7.9

*All charges are per gallon except CNG which is charged per therm.
**In lieu of annual per vehicle "tax stamp" purchase.
***The Energy Commission recognizes that as alternative fuels become commercialized, the tax issue could have an impact on the Highway Fund.

Electricity: Because of regulatory uncertainties, only one electricity price for EVs was developed. This is based on the municipal utilities' EV rates and the investor-owned utilities' proposed EV rates before the California Public Utilities Commission Low Emission Vehicle proceedings. Electricity prices were based on the proposed rates, the utilities' assumed vehicle recharging profiles for their various on- and off-peak rates, and the utilities' service charges for time of use meters. These prices varied between utilities, ranging from 5 to 10 cents per kwh, primarily due to differences in their assumed recharging profiles. Assumed growth rates of these electricity prices were obtained for specific utilities from the Energy Commission's ***1994 Electricity Report***. By and large, these growth rates are nearly flat in real terms over the next 20 years.

Electricity rates for EV charging are expected to remain relatively stable during the next 10 years. Assuming that no taxes are applied, electricity for EVs will continue to be less than half as costly as gasoline in some utility company service areas and only slightly less costly than gasoline in other areas. However, the major EV costs are likely to be associated with initial and replacement battery costs.

Taxes

As shown in Table 4-4, taxation plays an important part in the comparative retail prices of fuels, with M85 and propane taxed roughly on an energy-based par with gasoline and diesel. Taxes comprise from 27 to 35 percent of the retail prices of these fuels. CNG is currently taxed at a much lower rate, about 14 percent of the retail price, and electricity is currently untaxed. Since any future revisions to this tax structure remain uncertain, the current tax levels were assumed to apply for all forecast years.

Potential changes to these fuel tax rates could alter the comparative outlook for retail fuel prices. For example, federal or state action to tax all alternative fuels at the same rate could diminish the price advantage of CNG and electricity. Conversely, action to differentially raise tax rates on gasoline and/or diesel could improve the price competitiveness of all the alternative fuels. Staff examined how three differing transportation fuel tax structures could affect the future price of fuels. These results are presented in a staff report, ***1995 Transportation Fuel Tax Analysis***.

FUEL	UNITS	1994	2005	2015
Gasoline**	Gallons	12,785	12,718 - 12,728	12,694 - 12,708
Electric	KWH	425	2,659	4,601
CNG	Therms	8	150	210
Methanol***	Gallons	11	19 - 36	26 - 50
Propane	Gallons	62	69	78
Diesel	Gallons	2,226	2,794	3,211
Aviation	Gallons	3,116	3,334	3,451

Table 4-5
PRELIMINARY BASE CASE
TRANSPORTATION FUEL DEMAND FORECAST*
(Millions of Fuel Specific Units)

*Ranges are estimated using high and low methanol price projections. Higher methanol demand displaces gasoline use.
**Reformulated gasoline starting in 1996.
***Combination of M100 for transit buses and M85 for light duty vehicles.

DEMAND FOR ALTERNATIVE FUELS

Energy Commission staff prepared transportation fuel demand forecasts in response to the requirements of Senate Bill 1214 (Chapter 900, Statutes of 1991). This legislation directs the Energy Commission to forecast statewide and regional transportation demand under a variety of possible futures or scenarios, and to evaluate policies and programs to achieve a "least environmental and economic cost" transportation energy system.

The combination of availability and cost of AFVs, number of refueling sites, and relative costs when compared to conventional fuels has resulted in projections for a gradual increase in the near-term demand for alternative fuels. Table 4-5 compares the base case aggregate demand forecast through 2015 for all transportation sectors. This forecast includes present transit uses of alternative fuels, but does not

Table 4-6
PROJECTED LIGHT DUTY VEHICLE GASOLINE
DISPLACEMENT BY ALTERNATIVE TRANSPORTATION FUELS*
(Millions of Gasoline Equivalent Gallons)

FUEL	2005	2015
Electricity	312	644
CNG	163	232
M85**	7 - 17	12 - 26
Propane	31	33
Total Alternative Fuels	513 - 523	921 - 935
Light Duty Vehicle Gasoline Demand With Alternative Fuels	12,571 - 12,581	12,603 - 12,617
Light Duty Vehicle Gasoline Demand Without Alternative Fuels	13,084 - 13,094	13,524 - 13,538

*Assumes no change in travel demand or fuel prices between the two cases (gasoline only vs. alternative fuel availability).
**Ranges are estimated using high and low methanol price projections.

include any of the potential growth in additional uses of alternative fuels in medium and heavy duty trucks or transit vehicles.

Total gasoline demand in California is expected to remain relatively constant due to increases in alternative fuel use, fuel economy increases primarily from technology advances, and switching from gasoline to diesel for movement of goods. Both electricity and natural gas use in transportation in California are expected to grow over the next 20 years, based on current regulations and anticipated commercial availability of alternative fuel vehicles. The demand for methanol, propane, diesel and commercial aviation fuel is expected to increase slightly, in contrast to a relatively flat demand for gasoline.

Table 4-6 indicates the amount of gasoline displaced by alternative fuels used in light duty vehicles for the base case forecast. The total amount of gasoline displaced by AFVs is approximately 7 percent in the year 2015.

ENDNOTES

1. This table was compiled by Energy Commission staff from a variety of industry sources.

2. California Energy Commission, ***Resource Guide -- Infrastructure for Alternative Fuel Vehicles***, June 1995, p. 12, publication no. P500-95-004.

3. The gasoline-equivalent basis allows comparison among various transportation fuels based on their respective energy content. Due to the lower energy content of reformulated gasoline beginning in 1996, two sets of conversion rates were used to account for the amount of fuel that would be required to displace one gallon of gasoline. The 1994 equivalencies are: 1.154 therms of CNG, 2.03 gallons of M100, 1.76 gallons of M85, 1.26 gallons of propane, 0.90 gallons of diesel, and 0.90 gallons of aviation fuel. The 2005 and 2015 equivalencies are: 1.11 therms of CNG, 1.95 gallons of M100, 1.71 gallons of M85, 1.21 gallons of propane, 0.86 gallons of diesel, and 0.87 gallons of aviation fuel.

Chapter 5
NATURAL GAS MARKET TRENDS

INTRODUCTION

Natural gas will remain a major California energy source for decades to come. Gas supplies should be adequate and pipeline capacity to deliver the gas will exceed requirements for at least the next 20 years. Gas prices should remain affordable throughout the period. Since the price that producers charge for gas is now deregulated, the sale of gas has become highly competitive. Gas transmission is also becoming increasingly competitive. Thus, both state and federal regulatory agencies have instituted market-sensitive regulations designed to promote gas market competition and keep prices low, while maintaining service reliability.

This chapter discusses current natural gas market conditions in California and the rest of North America, followed by a discussion on how regulatory reforms have progressed since the ***1993 Fuels Report***. The chapter then focuses on the outlook for demand, supply, and price of natural gas for the forecasted 20-year horizon. It also addresses uncertainties associated with natural gas supply and price projections based on a scenario analysis approach with sensitivity analyses of specific key factors that influence the future of natural gas price and supply availability. The next section discusses the conceptual issues relating to integrated resource planning and demand side management and focuses on the current status of the two programs. The concluding portion of the chapter addresses the forecast of coal prices to specific coal-fired power plants in the northwest and southwest regions of the United States.

CURRENT GAS MARKET CONDITIONS

Natural gas market conditions look much as they did at the time of the ***1993 Fuels Report***. Abundant gas supplies are available from a diversity of geographical areas. Gas consumption has continued to rise slowly in California and the nation, while prices have remained low. Progress continues to be made in moving the gas industry toward increased responsiveness to market forces rather than regulatory control.

Gas Supply

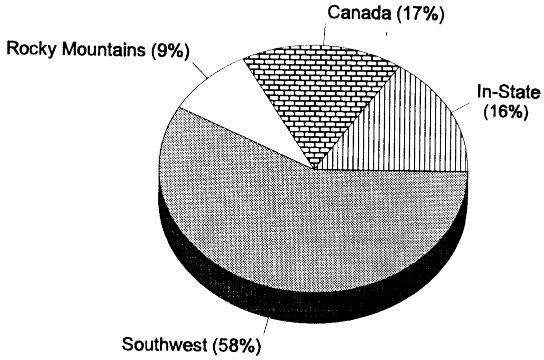
Natural gas continues to be abundant. Estimates of the size of the North American gas resource have increased substantially over the past few years, as technological improvements in exploration and drilling activity allow producers to access resources previously not considered recoverable.

An integrated, continent-wide gas market exists in North America, connected by a complex grid of long-distance interstate and international pipelines. The directions and magnitudes of gas flows in the pipeline system are sensitive to gas prices and other market forces. Major gas market events in any region affect all other regions through a ripple effect.

California gets its natural gas from a variety of geographical areas (see Figure 5-1). In 1992, 16

Figure 5-1

1992 California Natural Gas Supplies by Source



Perhaps the most significant recent development in gas markets is the rapid emergence of market centers. A market center is an area where several pipelines interconnect, with a central operator facilitating the interchange of gas. It is a location for one-stop shopping, bringing many buyers and sellers together to enhance competition and provide greater service reliability. In addition to facilitating sales transactions, a market center can provide a variety of services, including gas storage, balancing, accounting, and electronic information services. The price discovery and ease of transactions afforded by market centers can lead to lower gas costs.

percent was produced within the state. Another 17 percent came from Canada and 9 percent from the Rocky Mountains area. The remaining 58 percent came from southwestern states, principally New Mexico and West Texas.

Unlike the gas pipeline capacity shortages of the 1980s, California now has an excess of pipeline capacity connecting the state to its major gas supply regions. That capacity has increased from 4.6 billion cubic feet per day (BCF/D) during the late 1980s to approximately 6.8 BCF/D today. New pipeline capacity and expansion of existing capacity has enhanced California's ability to receive gas from all its major gas supply regions. That excess promotes competition among gas supply regions to sell gas to California, as well as competition among pipeline companies to deliver the gas. The competition helps keep gas prices low.

As gas regulatory reform has progressed over the last decade, the gas market has been witnessing the "commoditization" of gas. With each passing year gas is behaving more like traditionally unregulated commodities. The market continues to mature, competition intensifies, and barriers to market entry decrease. Large numbers of unregulated gas marketers and other entrepreneurs have emerged, focusing on providing new services and adding value wherever it will generate a profit. There is an active market in futures, options, swaps, and other financial tools to help producers and consumers manage risks. Several companies now offer computer-based, real-time, electronic data interchange systems for disseminating information and conducting gas sales.

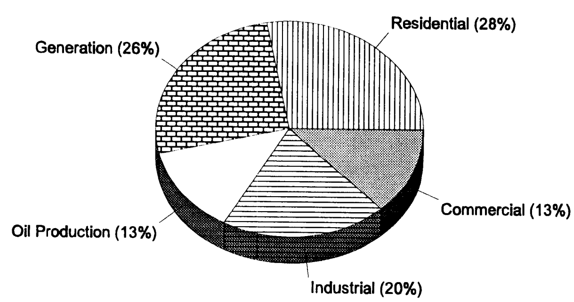
Gas Demand

Demand for natural gas in California and the nation has increased in recent years. Gas use is up due to its competitive price and environmental attractiveness when compared to oil and coal. California gas use in 1993 was 1.9 trillion cubic feet (TCF). Although gas demand has been growing in recent years, current gas use is less than California's peak gas demand of 2.5 TCF in 1973. Rapid gas price increases during the mid 1970s to early 1980s coupled with falling oil prices and a recession in the early 1980s resulted in significant decreases in gas demand.

Natural gas currently provides about one-third of all energy consumed in California. Gas use is second only to oil, which is by far the dominant energy source at 52 percent of the total. As shown in Figure 5-2, California gas consumption is fairly evenly spread over most end-use categories, or "sectors."

Figure 5-2

1993 California Natural Gas Consumption by Sector



Total = 1,916 Billion Cubic Feet

Gas Prices

Growing competition in the gas industry has caused gas prices to decline in recent years. The average United States wellhead gas price in 1994 was $1.83 per thousand cubic feet (MCF). Wellhead prices peaked in 1984 at $2.66 per MCF, about double the current price when corrected for inflation. Today's gas wellhead prices in real terms are about what they were when the federal government began to phase out wellhead price controls in 1978. Gas prices are also low compared to oil prices. The world price for crude oil in international trade in 1994 varied considerably, but was mostly within the range of $13 to $18 per barrel, which is equivalent on an energy basis to roughly $2.15 to $2.85 per MCF.

Unlike unregulated wellhead prices, the cost of transporting the gas from the wellhead to the consumer is regulated as a monopoly activity. Gas transportation in interstate commerce is regulated by the Federal Energy Regulatory Commission (FERC) while within California it is regulated by the California Public Utilities Commission (CPUC). Both regulatory commissions set rates based on the actual costs incurred to provide the transportation service (although discounts are permitted under certain circumstances).

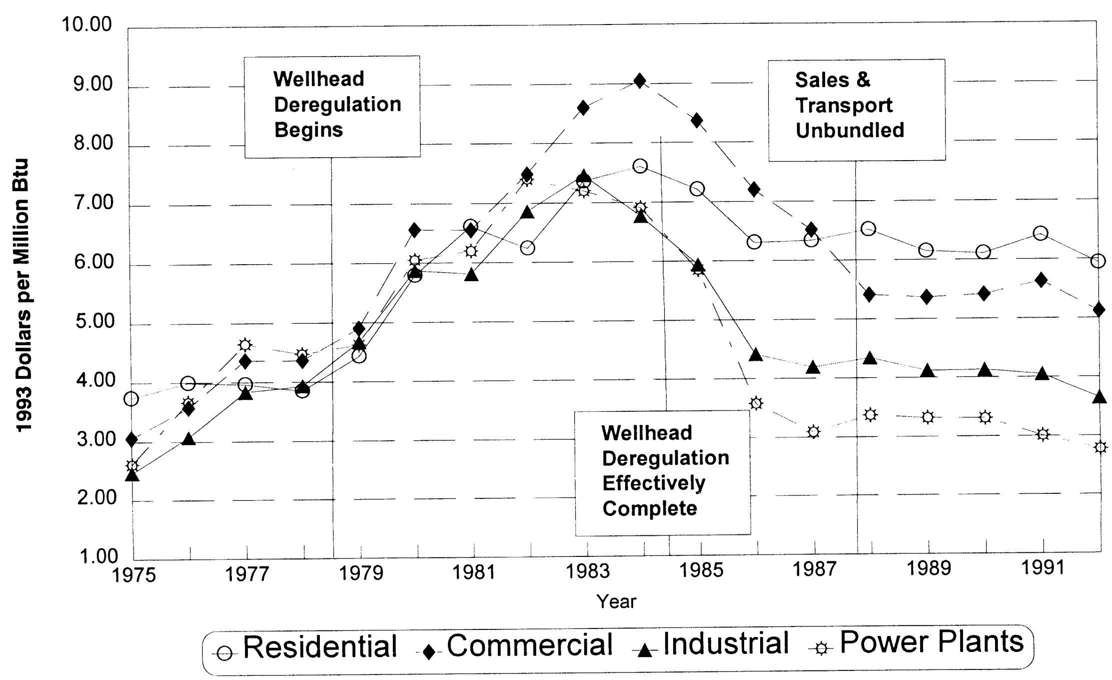
Figure 5-3 displays the price of gas to various sectors of California consumers since 1975. Prices used to be similar for all sectors. Prices diverged starting about the mid 1980s, when the CPUC moved to a cost-based rate structure. Residential rates are the highest because it costs more to serve small customers than large ones and because residential customers require the highest quality of service.

Residential and other small consumers of gas still receive traditional gas service from their local utility. Larger gas consumers (typically, industries and power generators) may purchase their own gas from producers or marketers and pay the utility to deliver it to their premises. Large consumers, however, may opt to buy gas from the utility and receive the same type of service as small customers.

Regulations

As discussed in the ***1993 Fuels Report***, the major building blocks are largely in place for a restructured,

Figure 5-3
California Natural Gas Prices by Sector



market-based natural gas industry in California. These major pieces are: deregulated wellhead gas prices; separate availability and pricing of gas sales, transportation, and underground storage services; nondiscriminatory provision of gas pipeline transportation; and rates for regulated services designed to promote economic efficiency.

Despite widespread agreement on the broad regulatory structure defined by these major building blocks, gas regulations continue to evolve. Regulators are focusing on two complementary ideas: instituting competition in place of regulation where feasible, and assuring that, where regulation is necessary, the rates are market-sensitive to promote economic efficiency. The following sections describe some areas in which the gas industry is grappling with ways to further increase competition and economic efficiency.

Incentive Ratemaking

Some aspects of the gas industry cannot be deregulated because they retain monopoly characteristics. Long-distance transportation (at least in part) and local distribution of gas through pipelines fall into this category. Even though these services are regulated, regulators can introduce some market discipline into utility provision of the services through the use of incentive ratemaking.

"Incentive rates" are rates designed to give the utility a financial incentive for superior performance from the ratepayers' perspective. Under a typical incentive rate, if the utility can provide services at lower cost, the utility and the ratepayers share the savings and everyone is better off. Properly designed incentive rates will provide utilities with greater flexibility to find least-cost options, as well as reward utilities for innovation and use of improved technologies. Further, incentive ratemaking can impose a lower administrative and regulatory burden on all participants in the regulatory process. Both common sense and experience indicate that the "carrot" of incentive rates works better than the "stick" of traditional ratemaking.

A form of incentive ratemaking now being tried experimentally in California is called performance-based ratemaking, or PBR. Under PBR the size of a utility's profits depends on its performance. PBR incentives are balanced because both rewards (for superior performance) and penalties (for substandard performance) are possible. Performance is measured in relation to a clear, objective benchmark that represents a reasonable approximation of the market environment faced by the utility. Of course, the point at which the benchmark is set is critical to the success of PBR.

PBR was applied first to the cost of gas purchased by gas utilities for resale to customers. Experimental PBR gas rates became effective for San Diego Gas and Electric Company (SDG&E) in August 1993 and Southern California Gas Company (SCG) in April 1994, and are expected soon for Pacific Gas and Electric Company (PG&E). PBR is being extended to include gas utilities' non-gas costs (so-called base rates). Experimental PBR base rates became effective for SDG&E in January 1995 and are being developed for SCG and PG&E. PBR rates for gas sales are being watched closely because of their potential to be applied to electricity sales as electricity regulatory restructuring proceeds in California.

On the national level, the FERC, which regulates interstate gas pipelines, is also experimenting with incentive ratemaking. The FERC has embraced the concept that, where discrete services it regulates are competitive, the rates should be market-based. In practice, the FERC sets a range within which rates are found to be reasonable and market competition is permitted to determine the price within that range. Where services are not sufficiently competitive to permit market-based rates, the FERC prefers incentive rates to traditional cost-of-service rates.

The FERC has already adopted market-based rates for some underground gas storage services and for gas inventory charges associated with gas sales by pipeline companies. The FERC is currently considering the extent to which incentive rates, now largely restricted to gas sales services, should be extended to gas transportation services. In some instances pipeline transportation services might be sufficiently competitive to permit market-based rates. The two most likely areas for market-based transportation rates are capacity release (discussed in the next section) and pipeline corridors between major market centers when several pipelines compete.

Capacity Release

The California gas utilities historically held the contractual rights for the use of all the firm (dependable) capacity on interstate gas pipelines coming to California. As the utilities' monopoly over gas sales ended in the late 1980s, they no longer needed all of the interstate capacity. The need arose to rationalize the gas transportation system by shifting a large part of the pipeline capacity rights to other parties who were now buying their own gas and needed a means to ship it to California. This rationalization has been slow and difficult because the old arrangements were fixed in place by long-term contracts. The existing contracts expire in stages over the next dozen years.

Under existing regulations, the utilities can reduce (but not eliminate) the financial impacts on themselves and their rate payers due to these contracts without waiting for contract expiration. They can release the capacity back to the pipeline companies, which will remarket the capacity. Alternatively, the utilities may market the capacity themselves, if they follow prescribed nondiscriminatory procedures. By regulation the maximum price the utility can charge, called the "rate cap," is the FERC-approved rate that the utility currently pays the pipeline. If the utility receives less than the rate cap for released capacity, it must come up with the remainder, because it still has an obligation to the pipeline for the full contract price.

Experience with capacity release has been mixed. On the plus side, large amounts of capacity have been released and remarketed, making firm capacity available to parties that previously could not obtain it. With the creation of a market in firm capacity, competition has been unleashed. This competition has driven down the price of released capacity on some pipelines, thus reducing gas costs for some California consumers.

On the negative side, utilities are still stuck with some unwanted capacity, for which they must pay the pipeline company. In addition, for the capacity released to other buyers, they must pay the difference for released capacity that sold at less than the rate cap. (In both cases, the utility passes the bill along to ratepayers.) Moreover, the capacity release procedures specified by regulation have proved cumbersome and expensive, forcing transactions in economically suboptimum directions. The FERC has made some improvements and is considering further changes. For example, the FERC has requested comments on whether the price cap should be lifted to allow the market to allocate capacity more efficiently. The market for released capacity may be sufficiently competitive to support unrestrained market-based rates.

Bypass of Utilities

Traditionally, utilities and pipeline companies have been partners in the gas industry. Pipelines purchased gas from producers, transported it to utilities, which then bought it for distribution and resale to consumers. As competition in the gas industry increased, it was natural, perhaps inevitable, that some degree of competition should creep into the partnership between utilities and pipelines. One form of competition appearing in numerous locations throughout the country is interstate pipelines bypassing the local utility and selling gas directly to consumers.

Now that two interstate pipelines enter California, rather than stopping at the state border as they all did prior to 1992, some large gas users in the state have the option of bypassing their utility. If the user is located close to one of the interstate pipelines, the pipeline might be able to offer a lower price than the tariffed rate charged by the utility. (Being regulated by the FERC, the pipelines are not bound by the rates that the CPUC sets for the utilities.)

If a gas customer bypasses the utility system, the utility foregoes the revenues it otherwise would have received. Under the current regulatory scheme, to achieve its authorized revenues the utility may need to raise its rates to remaining customers to cover fixed costs and make up the difference.

The utilities are battling to avoid bypass of their systems. The CPUC permits the utilities to negotiate special, discounted contracts with gas users who might otherwise bypass the utility. (Whether the rate payers or the utility shareholders must shoulder the cost of the discounts varies by utility.) The utilities also adopted major programs to cut costs and improve services in order to better compete with all their competitors, including pipelines and other energy types such as coal and electricity.

At the time of the ***1993 Fuels Report***, the Mojave Pipeline Company was proposing to extend its interstate pipeline, from its present terminus near Bakersfield, northward to Sacramento and the San Francisco Bay Area. The extension would considerably expand the opportunities for large gas consumers to bypass the utilities, principally PG&E.

The outcome of Mojave's proposal is still unclear as of this writing. Some of the proposed customers of the Mojave extension have withdrawn, hurting the outlook for the project. Nevertheless, the competition from Mojave's proposed extension has already affected the state because the utilities have reduced prices to potential bypass customers to retain their business.

The Los Angeles Department of Water and Power (LADWP), whose gas-fired power plants receive their fuel over the SCG system, is considering bypassing that utility. The current CPUC investigation to restructure the regulation of electricity in California is motivating electricity utilities, including LADWP, to look harder at ways to control costs. LADWP is considering building a pipeline from its power plants to connect to the Kern River/Mojave joint pipeline in Kern County, to avoid the gas utility's transportation charges.

THE FUTURE GAS MARKET

The Energy Commission's outlook for the natural gas market in California and the rest of North America is positive. Ample supplies of natural gas will be available with little or no curtailment, the price of natural gas will remain competitive with alternative energy sources (fuel oil, coal), and demand will continue to show strength for the next two decades. The environmental benefits of natural gas vis-a-vis alternative energy sources further supports the Energy Commission's basic conclusion.

Even with this optimism, the Energy Commission recognizes that the future direction of the natural gas market in California could vary considerably, depending on the direction of several energy markets, as described below.

- **Electricity Restructuring:** Since the CPUC issued its electricity "blue book" in April 1994 outlining a comprehensive restructuring of the electricity marketplace, energy market representatives, utilities, and regulators alike have invested considerable time developing a program that will eventually allow all customers an opportunity to select their suppliers of electric power and transmission service.[1] The resultant competition among electricity suppliers for access to customers is expected to lead to greater efficiency and an increased emphasis on cutting costs. After electricity restructuring, most new power plants are likely to be gas-fueled because they produce the cheapest electricity of all power plant options. Some experts expect these new power plants to cause a large increase in the level of gas consumption for power generation.

On the other hand, countervailing forces could tend to reduce gas consumption. It is unclear how new and efficient power plants would affect the use of existing power plants. If the new plants are used to replace old, inefficient, gas-fired plants, the total amount of gas consumed might decrease, even as total electricity generation from gas-fired plants increase. In addition, as competition is leading to lower electricity prices, electricity might capture some end-use markets that are now served by gas. Another reason for reduced gas competition in California could be due to increased purchase of cheap power from out-of-state facilities, reducing the need to generate electric power within the state.

Whether total gas consumption would increase or decrease as a net result of all these countervailing forces is currently unknown. Therefore, staff looked at sensitivity cases that assumed either lower or higher gas consumption for electricity generation than was assumed in the Base Case. These sensitivities and their effect on forecasted gas prices are described later in this chapter.

Nonetheless, the Energy Commission believes that electricity restructuring will be good for the gas industry because market competition encourages more efficient market activity. Gas and electricity will increasingly compete with each other, as both markets increasingly converge into a single energy market. Further integration is expected during the next 15 years, as the efficiency of gas-fired generators is improved and the cost of producing electricity is reduced to as little as three cents per kilowatt hour.[2]

Electricity restructuring will increase the use, for both gas and electricity markets, of market hubs and computerized services that allow customer access to immediate information on energy prices and availability. Customers will be able to choose the best combination of energy types for their needs, placing downward pressure on natural gas prices at the burner-tip. The downward pressure will reduce the likelihood of customers switching to alternate energy sources. The ultimate benefit, however, is contingent on how far regulators allow market competition to operate. The issue of electric restructuring will be fully addressed in the ***1996 Electricity Report*** that is underway at the Energy Commission.

- **Mexican Markets:** Mexican markets will also impact the direction of the natural gas market in North America during the next 20 years. The North American Free Trade Agreement certainly improves the likelihood that more gas produced in Mexico will penetrate markets in the United States and vice versa. Mexico has 187 TCF of potential reserves but does not have the infrastructure developed to bring much of that gas to the marketplace.[3] Several signs indicate that change may be on the horizon. In April 1995, the Mexican congress approved opening storage, distribution, and transmission to foreign investors. The following month, Mexico's Energy Minister told Canadian regulatory officials and pipeline companies that his country intends to compete with Canada for market share in the United States.[4]

  The improved ability of Mexican gas to travel to Northern Mexico and the United States ultimately depends on the actions of state-owned Petroleos Mexicanos (PEMEX), which holds all rights to exploration and production. According to the Canadian Energy Research Institute (CERI), 30 percent of the Mexican government's revenues come from PEMEX. CERI expects PEMEX to continue placing a high priority on developing supplies to the country's growing oil market. As a result, most natural gas development will continue to be associated, limiting growth in Mexican natural gas production capability.

  From the perspective of United States and Canadian producers and transporters, the opening of storage, distribution, and transmission systems in Mexico to foreign investors clearly improves the outlook for increased deliveries of gas to Mexico. Four companies presently have pipelines exporting gas to Mexico, with a combined capacity of 950 MMCF/D.[5] Other companies are presently targeting Baja California as the next place to build pipeline capacity to deliver gas to Mexico. These pipelines are designed primarily to serve power plants and cities along the United States-Mexican border which are moving away from the use of high sulfur fuel oil due to severe pollution problems in the region. With distribution open to foreign investment, additional Mexican markets beyond the immediate international border may soon be open to United States and Canadian companies.

- **Alternative Fuel Markets:** The alternative fuel market will clearly impact the outlook for natural gas. In the late 1980s, methanol was touted as the alternate fuel of choice in the transportation sector. Now, natural gas is beginning to assume that role, not only in California but also in the rest of the United States. Clearly, the ability of natural gas vehicles (NGVs) to penetrate conventional and alternate fuel vehicle markets will affect the outlook for the natural gas market. Estimates of future NGV demand in the year 2010 have been as high as 1.2 TCF, made by organizations such as the Natural Gas Coalition, the Gas Research Institute, and the American Gas Association. Recognizing the optimistic nature of the estimate, the group contends a "realistic" estimate of 370 BCF in the same year.[6] As part of the Energy Commission's work directed by Senate Bill 1214, the Energy Commission estimated that NGV sales in California will be about 3 percent of the total car or light-duty vehicle sales by the year 2010.[7] These estimates are subject to considerable uncertainty, given the uncertainty surrounding whether the California Air Resources Board can successfully implement its low emission standards on new vehicle sales beginning in 1998.

  Also within the alternative fuel market is the potential to displace natural gas as the so-called "fuel of choice" for stationary applications. The Energy Commission recognizes that other energy alternatives to traditional natural gas resources may become increasingly available during the forecast horizon, namely Liquefied Natural Gas (LNG) and synthetic fuels. LNG is already a viable energy source throughout the world, accounting for 3 TCF of natural gas consumed in 1993. Estimates suggests that worldwide LNG production, which comes primarily from Indonesia and Algeria, could increase more than two-fold by 2010.[8] The potential for LNG to increase its small North American natural gas market share ultimately depends on the amount of

LNG regasification capacity in the region. Four plants along the eastern seaboard and the Gulf of Mexico presently can regasify 1,002 BCF per year.[9] Each facility has sufficient space to expand capacity by an additional 50 percent. Due to the high cost of LNG versus pipeline gas, two of the plants are presently idle and the other two operate at much less than full capacity.

Synthetic natural gas produced through coal gasification and hydrogenation provide another alternative source of energy that could compete with the traditional natural gas supplies. Generally referred to as the "backstop" supply, synthetic fuels present an upper bound on natural gas prices because of the ability to produce it in effectively unlimited quantities at a certain price at some point in the future. The development of coal gasification still faces many technological challenges before becoming economically viable. As such, the Energy Commission does not expect these backstop alternatives to be commercially available for at least 15 years. Unforeseen market conditions could, however, accelerate the development during the 20-year planning horizon.

- **Interstate Pipeline Transportation:** A final point clouding the direction of the natural gas market is the industry's own gas transportation restructuring. On the positive side, pipelines and holders of firm interstate pipeline capacity (shippers) can release their capacity for use by other shippers through a capacity release program. This program has effectively created market-based ratemaking mechanisms to enhance market competition. Competition in this environment will be most effective as long as excess capacity is available. If, however, capacity is constrained and priced at the maximum rate, customers who would be willing to pay more than the full tariff rate may not be able to obtain the capacity.

FERC recently began a further investigation into market-based rates and several alternatives are being considered. For pipeline corridors where market competition is evident, FERC is leaning towards removing maximum tariffs from the competing pipelines. In regions with no competition, FERC has suggested the status quo. Hybrids combining both approaches have also been recommended. Whatever methodology is ultimately selected, it may be several years before a new market-based rate program is adopted in the interstate marketplace.

For interstate pipelines serving California, interstate transport rates are effectively market-driven. With approximately 2 BCF/D of excess capacity available, third-party shippers can obtain significant discounts to use the capacity for terms of varying lengths through the capacity release process. Capacity has been discounted as much as 95 percent and has often been discounted more than 75 percent in any given month. As a result, natural gas prices delivered to California utilities have been among the lowest in the nation. With significant levels of excess capacity to California anticipated through at least 2002, California end-users should continue to benefit from transportation competition.

At the utility distribution level, the extent of market competition is several years behind facilities subject to FERC jurisdiction. Even so, customers in California can negotiate discounted intrastate transmission rates but presently cannot bid for any unutilized in-state pipeline capacity. The strongest case for discounted rates usually applies to a customer who can show to the CPUC an "imminent" ability to bypass the utility if the bypass pipeline can serve that customer for a lower rate. To date, the CPUC has approved more than two dozen such contracts.

In Decision 94-02-042, issued February 16, 1994, the CPUC stated its intent to investigate in-state transmission competition. This investigation will likely become the driving stimulus to place the level of competition inside California on par with that experienced at the federal level.

The single most important transportation issue jeopardizing the positive outlook for natural gas during the forecast period is stranded pipeline costs. During the next several years, several significant contractual commitments between interstate pipelines and firm capacity holders will expire, leaving unanswered who will pay for pipeline capacity stranded after the contract's end. During the forecast period, PG&E's commitments on El Paso and Pacific Gas Transmission pipelines will expire, as well as SCG's holdings on El Paso and Transwestern. The largest piece, PG&E's 1,140 MMCF/D holdings on El Paso, will expire at the end of 1997. Depending on the direction of FERC in its market-based ratemaking investigation, end-use customers could pay considerably higher per unit transmission rates in the near future.

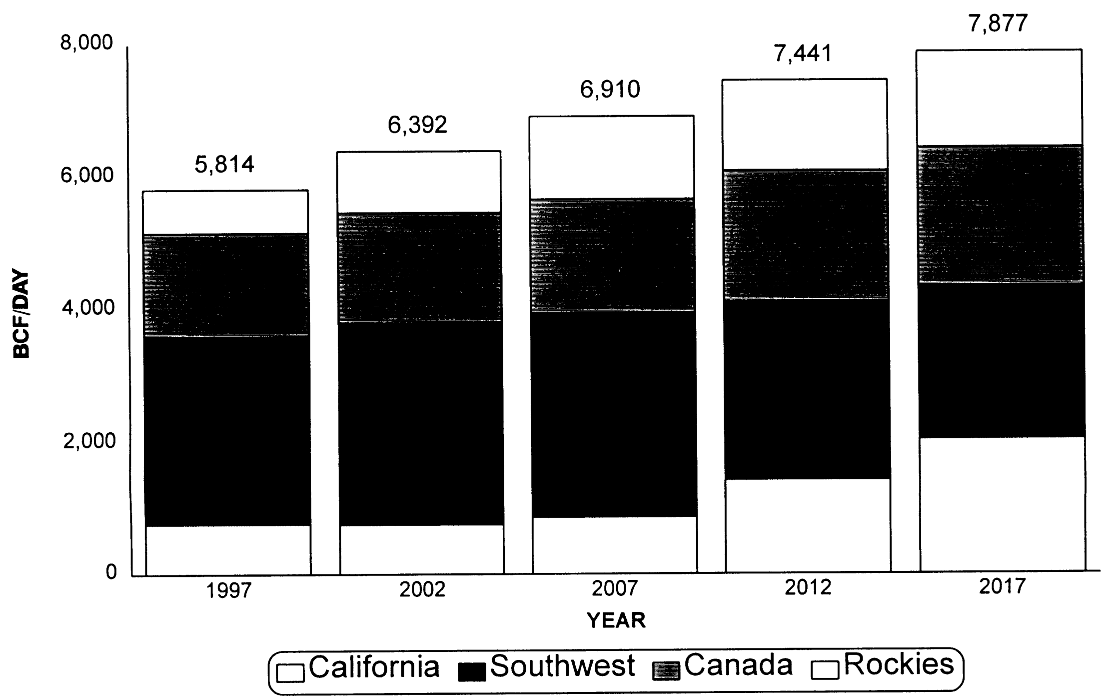
The remainder of this section provides the Energy Commission's Base Case assessment of the natural gas supply, demand, and price outlook for the next 20 years. Following the assessment are several sensitivities and scenarios considered in this analysis.

Natural Gas Supply Outlook

Natural gas supplies are expected to be abundant during the next several decades. The Energy Commission estimates a total resource base (gas recoverable with today's technology) for the Lower 48 of 1,056 TCF, enough to satisfy current production levels for the next 60 years. This estimate is conservative, given that a significant portion of Canada's 383 TCF of gas will serve Lower 48 gas markets as well. Furthermore, technological improvements in exploration and drilling activity should allow producers to access resources neither considered economically recoverable today nor part of the resource estimate. The pace of these improvements has been accelerated by the transition from a highly-regulated to a market-competitive gas industry during the past 15 years.

The Energy Commission's latest resource assessment offers several insights about natural gas supplies. First, the Gulf Coast region will continue to dominate the Lower 48 gas market, producing more than 8 TCF per year throughout the forecast period. Anadarko and Permian production will continue to show strength while the Rocky Mountains will play a significant role in meeting requirements in the Western United States. Canadian production will rise from 4.4 TCF in the 1992 base year to nearly 6.7 TCF in 2017. Much of this increase is fueled by exports to the United States, which is expected to surpass 3.2 TCF by the end of the forecast period. With respect to supplies available to California, Southwest gas will slowly relinquish its role as the dominant gas supplier to the state by 2017 (Figure 5-4). In the 1992 base year, Southwest suppliers held a 58 percent share of the market. With increased access to Canada and the Rocky Mountains due to the completion of the Pacific Gas Transmission (PGT) expansion and the Kern River pipeline, the Energy Commission estimates the Southwest

Figure 5-4
California Supply by Source



share to fall to 29 percent by 2017. Most of the remaining strength in Southwest market share occurs in the San Juan Basin. Driven mostly by coalbed methane production, San Juan market share increases to 43 percent in 2002 but drops to 27 percent by the end of the forecast period. Permian supplies to the state shrink to virtually zero as its share of the California market declines from 18 percent in 1992 to 2 percent by 2017.

Canadian supplies gain and retain one-quarter of the California market through the 20-year forecast period. Rocky Mountain shippers double their market share by 2017. California producers, while experiencing a decline in market share towards the end of the decade and the early part of the next decade, will realize significant market share gains thereafter. This gain will occur as long as California producers can take advantage of improvements in drilling technologies that lower drilling costs and increase success ratios in the future. The Energy Commission will further investigate this issue in the development of the ***1997 Fuels Report***.

Natural Gas Demand Outlook

The Energy Commission anticipates natural gas demand in the Lower 48 to reach 26 TCF by 2017, a 1.4 percent annual increase during the next 20 years. The projection is higher than that presented in the ***1993 Fuels Report***, which estimated a 1.1 percent increase. The higher demand estimates can be attributed to: 1) market competition, as described in the previous section; 2) changes in public policy designed for environmental protection, and 3) the emergence of new gas technologies in end-use sectors (e.g., more cost-effective appliances).

Within California, total natural gas demand is forecasted to grow 1.1 percent per year during the forecast period for all sectors (Table 5-1). The largest increase on a percentage basis is forecast to occur in the power generation (UEG and cogeneration) market, whose demand grows at a combined 1.9 percent per year. In absolute numbers, this increase amounts to more than 1 BCF per day of additional demand by 2015. Since environmental regulations severely limit the use of petroleum and coal in the state for stationary sources, natural gas has become the clear fuel of choice within the power generation sector. In other states with less stringent environmental restrictions and abundant resources of coal, natural gas demand is not necessarily the fuel of choice. As a result, demand growth for natural gas by electric generators outside California is less certain. As discussed in the previous section, however, demand for natural gas in the electricity generation sector will be influenced due to the electricity restructuring program underway in the state.

Table 5-1
NATURAL GAS DEMAND IN CALIFORNIA
(MMCF/D)

	1992	2002	2015	Pct Annual Growth Rate
Residential	1,332	1,453	1,609	0.8
Commercial	634	625	721	0.6
Industrial	1,130	1,077	1,170	0.2
Natural Gas Vehicles	0	78	136	N/A
Enhanced Oil Recovery	724	858	843	0.7
Utility Electric Generation (UEG)	1,535	1,307	2,221	1.6
Cogeneration	451	765	847	2.8
Total	5,806	6,164	7,549	1.1

Note: Annual growth rates are computed from 1992 to 2015.

Sensitivity analyses in the following section address these concerns further.

Residential and commercial demand for natural gas is expected to show only modest growth during the forecast period, increasing less than 1 percent per annum. This is due to increased energy conservation, technological advancements producing more efficient appliances, and demand-side management activities.

Besides the "traditional" demand sectors, the Energy Commission anticipates the development of a substantial natural gas vehicle (NGV) market. Demand for natural gas in the NGV market is expected to grow from 12 MMCF/D in 1997 to 136 MMCF/D by 2015, representing 1.8 percent of the total natural gas consumed (in 2015) in the state. Although not indicated in Table 5-1, the Energy Commission anticipates a 14 percent annual increase in NGV demand from 1997-2015, considerably lower than the 21 percent annual increase projected in the ***1993 Fuels Report***. The reduction is a result of independent analysis recently performed by the Energy Commission's Demand Analysis Office staff.[10]

Natural Gas Price Outlook

The Energy Commission forecasts natural gas prices both at the point of production (wellhead) and the point of consumption (burner-tip). Since 1989, the basis for all Energy Commission-sanctioned natural gas price forecasts has been the North American Regional Gas model, which computes a generalized equilibrium solution for supply, demand, and price in each region throughout North America. Energy Commission staff develop the input data and assumptions in cooperation with all segments of the gas industry in an open, public process. For more information on the model and methodology, see the ***1995 Natural Gas Market Outlook***.

Natural gas wellhead prices for the Lower 48 are expected to grow at an annual rate of 3.6 percent on a real basis over the 20-year forecast period, from \$1.62 per thousand cubic feet (MCF) in 1997 to \$3.28 per MCF in 2017 (expressed in constant 1993 dollars). The forecast is considerably lower than those prepared for previous fuels reports (Figure 5-5), primarily due to the Energy Commission's latest resource analysis reflecting lower capital costs and a slightly higher potential resource estimate.

Comparing specific producing regions except the Northern Great Plains, the Energy Commission expects the Rocky Mountains to become the least-expensive Lower 48 natural gas supply region at the wellhead after 1997. Alberta producers will provide the most attractive wellhead prices in Canada after 2002, with prices in British Columbia and Alberta virtually identical during the next seven years.

The relationship between wellhead prices in Alberta and the Rocky Mountains bears special attention. Historically, Alberta wellhead prices have been as much as \$0.50 per MCF lower than Rocky Mountain and other supply regions in the Lower 48. The Energy Commission's analysis suggests this price relationship will change by 2012. The shift occurs because Alberta's resource will be depleted more rapidly than the Rocky Mountains and therefore become more expensive to produce in later years.

End-Use Price Outlook

Most consumers will continue to experience increases in natural gas prices during the next 20 years. The Energy Commission projects that industrial gas prices (in 1993 dollars) will increase 1.4 to 2.6 percent annually between 1997 and 2015, depending on the utility service territory. Prices for natural gas consumed in the electric generation sector during that same period are expected to rise 2.1 to 2.7 percent per year, although prices will remain relatively constant for the next 5 to 10 years. Residential customers will experience rate changes ranging from a 0.1 percent decrease to a 1.2 percent increase on an annual basis, depending on the utility service area.

Figure 5-6 presents the utility electric generation forecasts for the three major utilities in California. Gas prices presented in this report are considerably lower than the ***1993 Fuels Report*** forecast. Three factors account for the decline. First, the Energy Commission's updated resource assessment reflects lower capital cost per unit of resource available, hence lowering wellhead price projections. Second, interstate pipeline transportation rates are lower, reflecting the impact of capacity release programs which allow customers to transport gas on the

Figure 5-5
U.S. Lower 48 Natural Gas Wellhead Prices

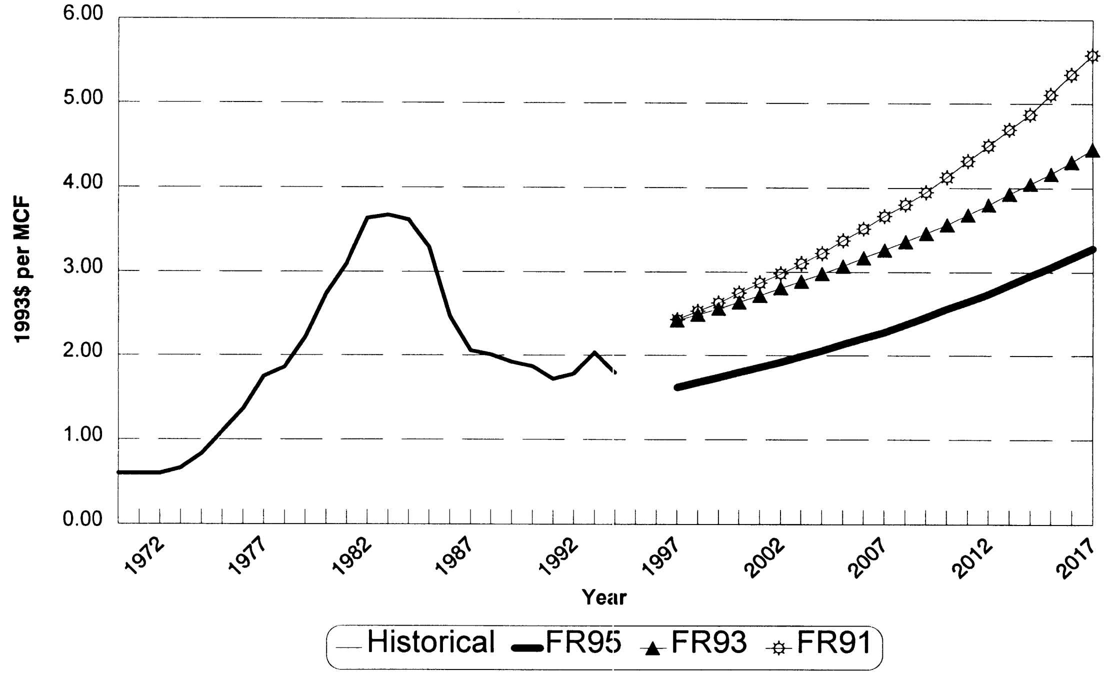
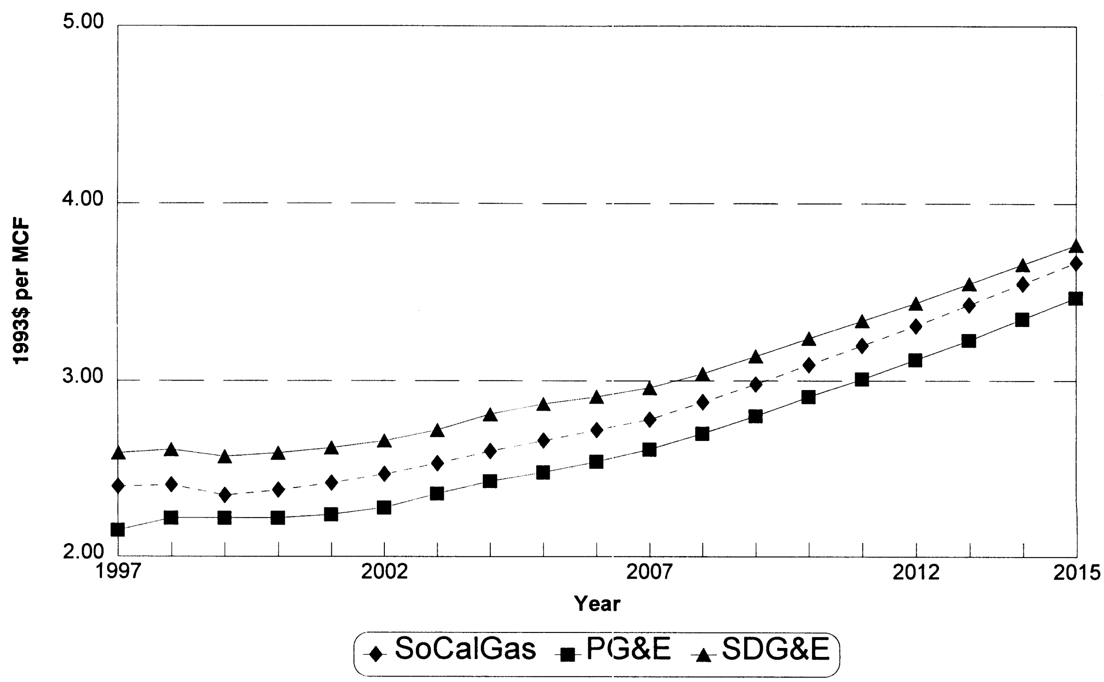


Figure 5-6
Regional UEG Natural Gas Prices



interstate pipeline system often at significant discounts. Finally, since competition has forced natural gas utilities to reduce their operating costs, intrastate transmission and distribution cost projections are lower. The combined effect of these changes produce lower price projections at the burner-tip.

Sensitivities

Given the uncertainty associated with the assumptions used in the Base Case, the Energy Commission prepared a series of sensitivity cases which test the impact of changing a single parameter on the natural gas price forecast. Several cases were reviewed, including changes in resource potential, backstop prices, discount rates, demand, and technological assumptions. The ***1995 Natural Gas Outlook*** details the sensitivity cases considered. A brief summary of the analysis follows.

Perhaps the greatest sensitivity on natural gas prices was on assumptions regarding the owner and producer's discount rates. The owner's discount rate is defined as the "rate used by the original owner of a resource deposit to discount cash flows resulting from the sale of leases to resource producers." The producer's discount rate is simply the required rate of return on equity for all investments. The Energy Commission staff equated both rates at 6 percent (real) in the Base Case. In general, lower owner discount rates produced higher prices throughout the forecast horizon with the greatest percentage impacting near-term price estimates.

Assumptions about the resource base and backstop price also produced significant changes to Base Case price projections. In the Low Resource sensitivity, Lower 48 wellhead prices increased 17 percent to 20 percent, while the High Resource sensitivity decreased prices 3 percent to 5 percent. The forecast was also sensitive to the backstop price. The Energy Commission determined that every $0.25 per MCF drop in the backstop price from the Base Case assumption of $5.00 per MCF reduces Base Case wellhead prices by $0.03-0.05 per MCF.

The market sensitivities tested by the Energy Commission did not produce a major impact on average prices and supplies for the Lower 48 and Canada in aggregate. Regional differences, however, told another story. Perhaps the most important sensitivity was the impact on natural gas flows to California if the transportation costs of the PGT expansion were rolled into the PGT rate base. Two options are under consideration at FERC: 1) "rolled in" which spreads out the capital cost of the expansion over all users of the system and 2) "incremental" which applies all capital costs to the users of the new facility components. The Energy Commission determined that natural gas flows to Southern California would increase with rolled in rates, but decrease slightly to Northern California.

Applying different assumptions about demand projections in sensitivity cases produced little impact with respect to demand assumptions in the Lower 48, California, and Mexico.

Scenarios

As in past fuels reports, the Energy Commission performed a scenario analysis to understand possible outcomes of natural gas supply and price trends under different "plausible" future circumstances. Scenarios produce a framework whereby future supply, demand, and price uncertainties can be investigated. Projections resulting from this analysis present a range of natural gas prices that can be expected due to changing market conditions.

Staff constructed two scenarios in addition to the Base Case price forecast. The Base Case assumes "business as usual," with a continuation of the present trends for all key gas price determinants consistent with the ***1993 Fuels Report***. The Competitive America and Natural Gas Dominance scenarios take broader energy market views. For each scenario, staff developed a set of assumptions for key determinants that impact future availability and price of natural gas in the United States and California. The assumptions were then used in the model to provide a set of gas price and supply projections.

The Competitive America scenario assumes robust economic growth, with market competition the driving factor. Environmental problems are remedied by the market with reduced oversight by regulatory agencies. Rapid technological development is assumed to occur, which increases the resource base and decreases the costs associated with bringing the resources to market. Jobs are created as environmental goals are met, and cleaner burning residual fuels and coal emerge as viable alternatives to natural gas. Fuel competition is strong, and natural gas eventually loses significant market share to other fuels.

In Competitive America, oil and coal emerge as viable competitors to natural gas. As a result, natural gas consumption in the Lower 48 declines to 20.3 TCF by 2017, 22 percent below the Base Case. Wellhead prices increase only 2.5 percent per year through the 1997-2017 forecast period. California citygate prices increase at a modest 2 percent per year.

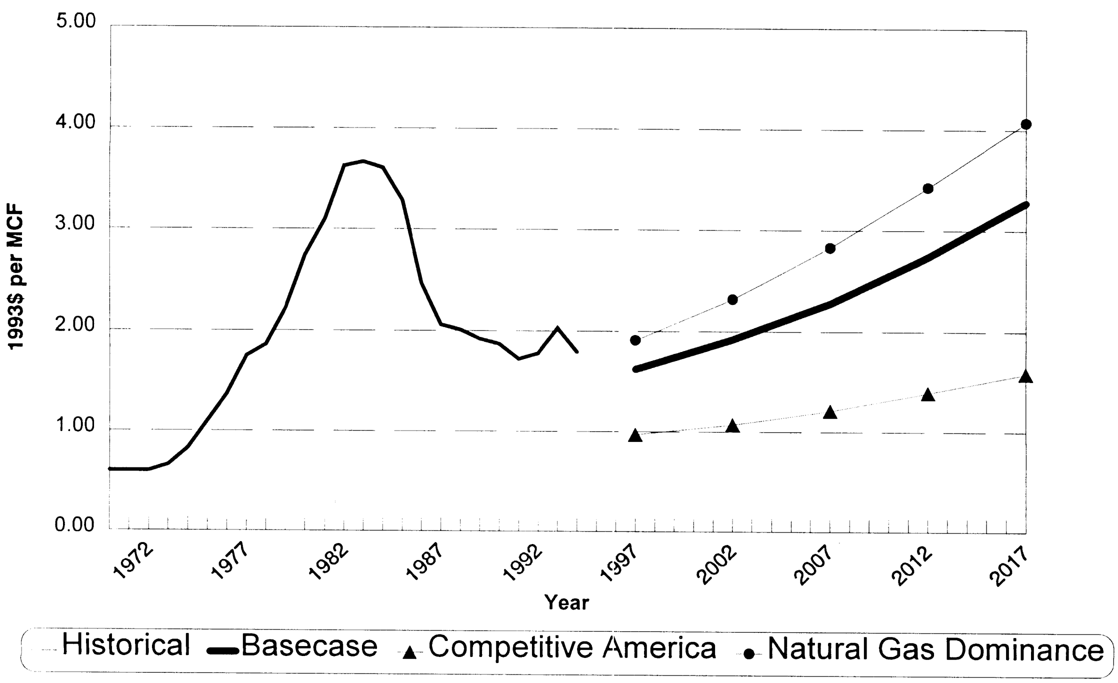
The Natural Gas Dominance scenario assumes increased natural gas usage due to efforts to reduce emissions from stationary and mobile energy sources. Specific regulations forbidding both oil and coal use force increased natural gas use in electricity markets. Furthermore, the nation as a whole continues its push away from nuclear power, resulting in the phase-out of nuclear power in the United States as licenses expire in the various nuclear power plants. Natural gas and electric vehicles penetrate the transportation market, with demand increasing substantively. With more stringent rules in place due to policies outlined in the federal Clean Air Act, costs associated with developing and producing natural gas increase.

To meet the increased demand in the above scenario, natural gas production grows to 27.5 TCF by the end of the forecast period, 5.9 percent above the Base Case. Lower 48 wellhead and California border prices escalate at 3.9 percent and 4.1 percent per year, respectively.

Figure 5-7 compares the Lower 48 wellhead prices in the Base Case forecast with the two scenarios just described. Compared to the Base Case, the Competitive America case is $0.65 per MCF lower in 1997 and $1.70 per MCF lower in 2017. Wellhead prices in the Natural Gas Dominance case are $0.29 per MCF higher in 1997 and $0.79 per MCF higher in 2017.

The two scenarios demonstrate the impacts of uncertainty in key determinants of future natural gas prices. They do not, however, represent a projection of gas prices but indicate the outer limits of the excursion of prices above or below the Base Case forecast. The Energy Commission believes these extreme forecasts are not sustainable, considering that market forces would tend to counter balance the

Figure 5-7
U.S. Lower 48 Natural Gas Wellhead Prices
Scenario Comparison



effects that either lower or raise gas prices. However, its use is recommended in electricity resource planning proceedings for analyzing the impacts of natural gas price forecast uncertainty.

INTEGRATED RESOURCE PLANNING

The main objective of a gas integrated resource planning (IRP) process is to achieve the lowest total cost of service by considering all supply and demand side options. The Energy Policy Act of 1992 (EPACT) directed states to consider the use of IRP for natural gas local distribution companies/utilities. The CPUC began a proceeding in 1993 to consider compliance with EPACT.

Since the late 1970s, the natural gas market has been undergoing significant restructuring and deregulation resulting in a more competitive market with lower gas prices. The current natural gas market is more competitive today due to the following: utilities are no longer the sole provider of gas; utilities' sales and transportation functions have been separated; utilities sell gas only to core customers (those that have not aggregated to purchase their own supplies); and expansions of interstate pipelines to California increased competition for gas supplies, thereby reducing gas costs in the state.

Because of deregulation and the level of competition existing in the gas market, utilities in California already perform informal IRP processes to enhance market share and corporate viability. The process begins with forecasting demand, including analyzing economic sensitivities and scenarios for a range of possible futures. Resource options, which exist as supply and demand side management (DSM) options, are then assessed. All potential resource options compete for demand in various econometric models to determine the optimal resource mix.

Two issues exist in using the IRP process for gas. First is the issue of whether or not gas DSM should be considered as a factor in the demand forecast or as a resource option with a derived, associated cost. In the natural gas price and supply forecast presented in this report, gas DSM is included as a reduction in the demand forecast. Gas DSM for this purpose incorporates existing building and appliance standards, government programs, and utility programs. Estimating the extent to which pipeline demand or capacity-related costs can be avoided by future DSM is a difficulty experienced by utilities implementing IRP.

Second, there is a dispute about whether IRP should be employed from a utility/ratepayer perspective or a societal, public perspective. The latter may involve longer time horizons, smaller discounting of the future, and inclusion of environmental externalities.

Several benefit/cost (B/C) tests exist to measure and evaluate DSM programs. The following B/C tests are presently utilized: participant, societal total resource cost, utility, total resource cost, and ratepayer impact measure test. The specific economic variables included depend upon each test's intended use and which of the stakeholders' perspectives it represents. For example, the societal total resource cost test examines environmental concerns and societal costs and benefits of DSM programs.

Critics of gas IRP claim the potential benefits are inherently less than those from an electricity IRP process. They contend that supply-side decisions for gas utilities do not imply the large, long-term, irreversible cost commitments experienced in electricity and that the costs avoided by implementing DSM are less for the gas industry than electric.[11]

Proponents believe there are many benefits from gas IRP which provide: information critical to supply portfolio planning, support for environmental objectives, information essential to determining system reliability and capacity needs, a methodology to assess risk associated with supply decisions and system investments, and a process useful in evaluating and establishing energy policy. A key component of gas IRP is DSM of natural gas supplies, the subject of the next section.

DEMAND SIDE MANAGEMENT

DSM has been aggressively pursued to meet California's growing energy needs while minimizing unnecessary growth in energy delivery infrastructure. Cost-effective energy conservation is less expensive and cleaner environmentally than building and operating new power plants or supplying and burning natural gas. Energy conservation is the result of many public and private programs and individual choices.

Fundamental restructuring in the natural gas industry has significantly affected both industry purchase decisions and natural gas DSM. In the 1980s, CPUC and FERC were restructuring the natural gas industry to increase competition and thereby reduce customer costs. The major changes were the separation of customers into "core" and "noncore" categories and the unbundling of transportation rates. These changes reduced the acquisition costs of gas and resulted in some DSM programs creating more revenue losses than cost reductions, reducing utility interest in DSM. However, DSM continues to evolve as a strategy in California's energy future.

Natural Gas Savings

The cumulative natural gas savings from all utility programs, building and appliance standards, public agency programs, and naturally occurring conservation during 1992 was 3.8 billion therms.[12] This cumulative impact includes remaining effects in 1992 of program expenditures in prior years.

From natural gas investor owned utilities' (IOUs) programs in 1994, 35.8 million therms of natural gas were saved through conservation and energy efficiency DSM efforts, less than 1 percent of California's total natural gas demand. By 2010, PG&E is projected to save 4 percent and SCG 2 percent of their respective core demand.[13]

Factors Influencing Natural Gas DSM

In 1995, the reasons for continuing DSM programs are changing. The energy market nationally, and in California especially, is undergoing considerable changes that influence prospects for natural gas DSM in the future. Among the influencing factors are air quality considerations, performance-based ratemaking, legislation for social program surcharges, and electric industry restructuring. California's IOUs, and municipal utilities as well, are responding to the changes in today's energy market by proposing to reduce budgets allocated to DSM programs, revising the goals of these programs, and reevaluating the methods used to determine cost-effectiveness of their programs. Collectively, California IOUs spent 92 million dollars in 1994 on natural gas DSM programs and have budgeted 104 million for 1995.[14] Although this is a slight increase, the 1995 budgets are down 20 percent from the 1993 actual budgets totaling $129 million.

Industry Restructuring

IOUs are attempting to reduce their rates in anticipation of increased competition in a restructured environment. Reducing DSM program spending through changes in funding sources, rate designs, and program designs help to keep rates low. Ultimately, getting the funding for DSM programs out of rates and into a non-bypassable distribution charge that would be collected from all energy users, not just IOU customers, appears to be a main utility goal as suggested by utility support of related legislation. Options for spending DSM money collected in this fashion range from continued utility programs to a statewide consortium or agency.

Through 1994, DSM programs have been paid for by the customers through their rates. The CPUC approves the IOUs' DSM programs and budgets and allows approved costs to be paid back in the rates. Since DSM reduces utilities' revenues by reducing consumption, the CPUC allows IOU shareholders to get earnings from successful DSM programs as an incentive for them to pursue energy conservation.

Performance Based Ratemaking (PBR)

As an alternative to traditional rate design, the IOUs are exploring PBR. The implications of PBR on DSM could be large and negative but are speculative at this point. At least one utility proposes to redesign its DSM program in response to anticipated competition whether or not PBR is approved. Some issues being considered by the utilities in their respective PBR/DSM proposals include: rate design impacts on utility and customer incentives to conserve, what the redesigned programs will include, how low-income programs will fare, and the impact on the shareholder incentive mechanism and reporting requirements. The objective will be to maintain the incentive both for the customers to participate and for the utilities to provide energy conservation and efficiency measures.

Air Quality Interaction

The benefits of improved air quality due to conservation continue to be investigated and pursued. One IOU reports reductions of 3.4 million tons of CO2, 1,379 tons of SOx, and 5,063 tons of NOx from its 1994 conservation and energy efficiency programs' electric and natural gas savings.[15] Air quality agencies and districts continue to explore incentives for smaller customers to implement natural gas conservation technologies that will result in emission reductions.

In 1993, the South Coast Air Quality Management District (SCAQMD) adopted the Regional Clean Air Incentives Market (RECLAIM) which allows SOx and NOx generating facilities to buy and sell emissions credits. RECLAIM inherently has a financial incentive for end users to conserve and use energy more efficiently. In addition to RECLAIM, SCAQMD has designed measures intended to provide conservation incentives to a variety of sources too small to be included in RECLAIM in the residential, commercial, and industrial sectors. The specific measures targeting natural gas DSM proposed in the 1994 Air Quality Management Plan are: Area Source Credit Program for Commercial and Residential Combustion Equipment; Efficiency/Energy Conservation - Area Source Credits measure; and Clean Stationary Fuels, a fuel substitution measure.[16]

Fuel Substitution and Load Building

Fuel substitution measures such as replacing electric space heating with natural gas furnaces are programs which promote the customer's choice of natural gas rather than another energy source. The SCAQMD measure, Clean Stationary Fuels, is intended to phase-out use of fuel oil and solid fossil fuels from stationary combustion sources to achieve emission reductions. The CPUC uses another definition for fuel substitution. It only applies to programs that result in an end user switching from one utility fuel to another.

Mobile source emissions reduction efforts such as the utilities' low emission vehicle programs are included in some utility DSM programs because the purpose is to influence consumer demand for energy. According to the CPUC definition, the fuel switching that occurs in the transportation sector from gasoline to alternative fuels such as compressed natural gas (CNG) and electricity would qualify as a load building program rather than fuel substitution since gasoline is not a utility fuel. Alternative transportation vehicles and fuels such as CNG are being developed and commercialized to achieve emission reductions and to some extent for energy security reasons.

Natural Gas DSM Goals

To better understand and evaluate the potential for future natural gas savings from DSM, the Energy Commission is building a projection methodology that will be available for demand forecasting efforts in the next ***Fuels Report*** cycle. In addition to this forecasting effort, the Energy Commission is participating in California Conservation Inventory Group and California Demand-Side Management Measurement Advisory Committee work to develop and implement contracts to further the state's knowledge of DSM results to date and future potential.

In May 1995, the Energy Commission began a collaborative effort called Energy Efficiency Services Working Groups. The goal for this group is to make a tangible contribution to enhancing opportunities for consumer choice of DSM and other unbundled energy services compatible with electric industry restructuring and societal economic efficiency. Through this process, the Energy Commission hopes to develop the best policies for publicly funded programs and to encourage private businesses to deliver energy efficiency services so that consumers have meaningful choices and are in a position to exercise that choice. The program goals and possibilities for publicly-funded DSM will also impact natural gas DSM roles utilities are expected to play in the future.

FORECAST OF COAL PRICES

California's primary interest in coal is for production of electricity in other states which is transmitted to California to meet part of our total energy demand. The price of coal affects both the generation of electricity at power plants owned by California utilities and the cost to produce coal-fired electric generation which is surplus to the regional needs. This surplus energy from base load coal generation plants is made available to California utilities. The forecast of price and availability for such surplus energy has an impact on future electric generation capacity addition decisions for California utilities.

As in the last several Fuels Reports, coal prices are forecast for specific electric generation plants in the western states. Compared to previous forecasts, the current forecast of coal prices (in 1993$) are slightly lower. This forecast is available in a report entitled ***Delivered Coal Price Forecast: 1995-2015***.

There are a number of factors that may cause a change in the future price of coal for Mohave and Four Corners. At Mohave, these factors include: 1) uncertain costs for slurry pipeline refurbishment to extend its operation beyond its design lifetime of 2005, 2) proposals by the Secretary of Interior and the Hopi Tribe for Mohave to fund a water pipeline from Lake Powell to replace the water source for the slurry pipeline, and 3) the potential for increased coal royalties paid by Mohave when the reopeners are exercised in 1997. Four Corners may be affected by: 1) the expiration of Navajo tax waivers on the Four Corners plant and on the Navajo Mine which supplies coal to the Four Corners plant, and 2) who will be responsible for paying mine closing and retiree health costs incurred after mine closing.

The forecast assumed that the above factors would be more than offset by the effects of increased competition resulting from the restructuring of the electric energy industry as well as continued improvements in productivity at the subject coal mines. It is possible that these effects may be stronger or weaker than the forecast has assumed. It is conceivable that the effect of the factors listed above, and other unforeseen factors, could result in coal prices that are significantly higher or moderately lower than those provided in the forecast.

ENDNOTES

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Chapter 6
CONTINGENCY PLANNING ISSUES

INTRODUCTION

The ***California Energy Shortage Contingency Plan*** is activated in the event of a shortage of electrical energy or fuel supplies to protect public health, safety, and welfare (Public Resources Code Section 25700 et seq.). For planning purposes, the Energy Commission considers a shortage to mean an actual or potential loss of supply which significantly impacts the state's energy systems and economy. In a natural disaster, such as earthquake, fire or flood, the Energy Commission works closely with the Governor's Office of Emergency Services (OES) to ensure that fuel supplies for emergency and essential services are available.

Since each energy shortage is unique, it is impossible to envision every event or combination of events which might qualify as an energy emergency. Instead of developing a separate response plan for every type of shortage, one flexible plan has been developed which is designed to work in any emergency. At the heart of the plan is a management structure which identifies the working relationship among people and provides a process to make those relationships work in a crisis. The plan represents a dynamic planning process with the flexibility both to evaluate and define a potential emergency, and to respond adequately to any shortage.

The plan relies on a mixed strategy response to an energy shortage. The plan uses a free market approach with phased government intervention only to the extent necessary to protect the public interest and as appropriate to the severity of the shortage. Activation of specific programs described in the plan occur only when an energy shortage substantially disrupts California's economy and normal operation.

The Energy Commission's Contingency Planning Unit provides ongoing strategic planning to enhance both the state's energy emergency and overall emergency preparedness. Planning is done in coordination and cooperation with OES, as well as other state, federal, and local agencies. Planning responsibilities include: assistance to local jurisdictions, economic considerations, revisions to the ***California Energy Shortage Contingency Plan***, and scenario-based exercises to train Energy Commission staff and evaluate the plan. In the next revision process, the Energy Commission will incorporate the Standardized Emergency Management System (SEMS) into the current management structure. SEMS is a five level, five function organizational framework designed to provide an effective response to a multi-agency, multi-jurisdictional emergency. This management system provides an umbrella under which all response agencies may function in an integrated fashion. SEMS is designed to be flexible and adaptable to the varied disasters that can occur in California. By state law, all state agencies must use SEMS by December 1, 1996, when responding to emergencies involving multiple jurisdictions or agencies.

LOCAL GOVERNMENT ASSISTANCE PROGRAM

The purpose of the Energy Commission's Local Government Assistance Program is to help local jurisdictions to develop or revise their own local energy shortage response plans, in a manner compatible with OES planning and SEMS. The objective is to enhance a local jurisdiction's capability to manage the impacts of a disruption to the supply and distribution of petroleum, natural gas and electricity. By ensuring that the local jurisdictions are prepared for an energy emergency, the state can ensure a more coordinated and timely statewide response.

The Energy Commission began a program to assist local jurisdictions with energy emergency planning when the ***1988 California Energy Shortage Contingency Plan*** was adopted. Since at that time many local plans did not address energy shortages or were out of date, the Energy Commission began a local government pilot program. The six pilot counties selected were: Lake, Sacramento, San Bernardino, San Francisco, Tulare, and Ventura.

Working closely with the six pilot counties, the Energy Commission developed the ***Handbook for Preparing a Local Energy Shortage Response Plan***. This handbook provides guidelines to assist local governments in developing a customized energy shortage response plan suited to their specific needs. It also identifies the major components of a local plan and includes instructions on how to lay the groundwork and develop the plan, building upon existing resources, authorities and communications systems. The six counties are now better prepared to manage an energy shortage.

The next step in the local government program was providing financial assistance to local governments to develop an energy emergency plan. In December 1992, the Energy Commission awarded a total of $1,085,000 from the Petroleum Violation Escrow Account to 14 local jurisdictions. The jurisdictions that received grants were: Alameda County, Berkeley, Butte County, Lake County, Los Angeles County Metropolitan Transportation Authority, Mendocino County, City of Sacramento, San Diego County, San Francisco, San Joaquin County, San Luis Obispo County, San Mateo County, Ventura County and Yolo County.

When these grants were completed in the autumn of 1995, an additional 14 jurisdictions were better prepared to respond to an energy shortage. The Energy Commission remains committed to the importance of local energy emergency planning and will continue to provide technical assistance to each local jurisdiction request.

FINANCIAL INSTRUMENTS

The Energy Commission's ***Regional Petroleum Product Reserve Feasibility Study***, completed in 1993, determined that a physical petroleum product reserve in California would not be an economically feasible method of mitigating the effects of price spikes during a supply disruption. An alternative to a physical reserve is the use of financial instruments such as forward, futures and option contracts. These contracts, or "paper reserves," could be used to mitigate price shocks that may accompany a fuel supply disruption. Use of contracts has been developed for the purpose of reducing or eliminating the risk that the price of a commodity will rise before the time of the purchase.

Option contracts have been identified as having the greatest potential benefit for California. The option contract grants the holder of the contract the right, but not the obligation, to purchase or sell a commodity at a specified price on or before a specified date. Options on crude oil and gasoline are traded on the New York Mercantile Exchange and are currently used by several state and municipal government agencies and public utilities throughout the United States.

Although financial instruments could be beneficial in mitigating price shocks, there are limitations in the usefulness when the commodity is simply not available. For example, during a natural disaster such as an earthquake in California, supplies may be temporarily unavailable due to damage to refineries, pipelines, highways and other parts of the distribution system. At such a time, a refiner may be temporarily unable to supply the volume of fuel under contract.

ECONOMIC ASSISTANCE PROGRAM

The Contingency Plan includes an Economic Assistance Program in recognition that during a severe energy supply shortage, when fuel prices may rise sharply, low-income households may be disproportionately impacted. Therefore, the Energy

Commission, in conjunction with the Department of Economic Opportunity (DEO), has developed stand-by options for providing economic assistance for the energy needs of low-income individuals, targeting the working poor.

The stand-by options designate the augmentation of existing economic assistance programs to help with increased transportation, space heating and cooling costs. The two programs designated are the Low-Income Home Energy Assistance Program and the Community Services Block Grant. By augmenting existing programs, the emergency options can use an established network of community-based organizations and eligibility requirements, responding to community-specific needs.

At the time of implementation of stand-by options, an assessment of poverty-related needs and available financial resources, plus a priority list of feasible goals and strategies can be immediately provided by the annual Community Action Plans. These plans, prepared by local antipoverty agencies in each of the 58 counties, also identify minimum requirements and coordination of services to avoid duplication. The programs reflect the principles of self-help and flexibility, with emphasis on local determination of need.

During an emergency, DEO has the ability to respond quickly in providing services, as demonstrated following the Loma Prieta earthquake in 1989 and the Northridge earthquake in 1994. During times of emergency, DEO may implement an emergency policy, waiving some restrictions or requirements to expedite the process. Enacting an emergency policy allows the flexibility to provide: self-certification of eligibility, an increase in the dollar amount allowed per household, and authorization of more energy-related devices.

EMERGENCY RESPONSE

The Contingency Plan is operational and flexible, designed to respond to any energy emergency, whether a man-made or natural disaster. In both types of events, the Energy Commission has a vital emergency response role to coordinate petroleum stocks essential to the relief and aid of the lives and property within the emergency area. The Energy Commission will work with the Office of Emergency Services to prioritize and divert petroleum supplies into a disaster area or in support of disaster mitigation operations.

As directed, one of the functions of the Energy Commission is to ensure the adequate supply of fuel for public health, safety and welfare. In an emergency, the Energy Commission may use its Petroleum Fuels Set-Aside Program in the Contingency Plan to obtain fuel for emergency responders and essential service providers who are unable to obtain sufficient fuel at any price. The Set-Aside Program has two components: an informal process and a formal program. The informal process is for immediate response to a specific, isolated need, implemented through direct communication with fuel suppliers.

By contrast, the formal Set-Aside Program would respond to a severe, more widespread and prolonged shortage, a measure of last resort. The Energy Commission has developed a computerized application procedure for this formal program. The Energy Commission has made available California's software program and instruction manual to other interested states and the United States Department of Energy. In addition, the Energy Commission has provided training on the use of the program to state counterparts in Nevada and Arizona.

The following examples of responses in the past two years illustrate the use of the plan, and the informal Set-Aside Program, during the two types of emergencies, a natural disaster and a man-made disruption:

- **Natural Disaster (Northridge Earthquake, January 17, 1994)**: The Energy Commission provided the Governor with damage assessment to crude oil pipelines, identifying alternate transportation modes for delivery of crude oil to Los Angeles refineries. Using the informal Petroleum Fuels Set-Aside Program, the Energy Commission arranged for diesel delivery to the Thousand Oaks 911 Center. The fuel was essential to operate their back-up generator until electrical service was restored.

- **Man-Made/Regulatory Event (Clean Diesel Transition Problems, October 1, 1993)**: The Energy Commission provided the Governor and CARB with refinery production volumes, retail and wholesale price information, and terminal deliveries. The analysis indicated that supplies were adequate, although there were some minor delays in the distribution system. Using the informal Petroleum Fuels Set-Aside Program, the Energy Commission arranged for the delivery of diesel to the Safeway Distribution Center to ensure critical weekend grocery deliveries.

The Energy Commission has also provided energy impact analyses on numerous other emergency events, such as refinery fires, wildland fires, floods, storm damage of electrical and natural gas systems, and petroleum pipeline breaks.